VSB TECHNICAL UNIVERSITY OF OSTRAVA | FACULTY OF ELECTRICAL ENGINEERING AND COMPUTER SCIENCE

MV Generator protection with ABB IED

VN generátorová ochrana s ABB IED

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Diploma Thesis

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Abstrakt

Diplomová práce se věnuje chránění generátoru vysokého napětí za pomocí ochranného terminálu ABB. Popisuje teoretické základy ochranných funkcí generátoru, podrobně se soustředí na vybrané funkce, a to jmenovitě na diferenciální, zemní a ochranu proti ztrátě buzení generátoru. Praktická část popisuje způsob testování ochranného terminálu ABB REG630 a bude použita jako podklad pro budoucí školení. Všechny tři typy ochranných funkcí byly rozebrány v teoretické části, dále naprogramovány a nastaveny pomocí softwaru PCM600 a konečně otestovány za pomocí školícího panelu a testeru Omicron.Vyhodnocení výsledků je přehledně zobrazeno za pomocí tabulek a grafů.

Klíčová slova

Ochrana generátoru VN; diferenciální ochrana; zemní ochrana; ztráta ochrany buzení; simulace.

Abstract

The diploma thesis deals with the protection of a medium voltage generator using an ABB protection terminal. It describes the theoretical foundations of generator protection functions, focusing in detail on selected functions, namely differential, earth-fault and loss of excitation protection of a generator. The practical part describes how to test the ABB REG630 protection terminal and will be used as a basis for future training. All three types of protection functions were analyzed in the theoretical part, further programmed and set using PCM600 software and finally tested using a training panel and Omicron tester. The evaluation of the results is clearly displayed using tables and graphs.

Key Words

MV generator protection; differential protection; earth-fault protection; loss of excitation protection; simulation.

Acknowledgement

I would like to thank prof. Ing. Radomír Goňo, Ph.D. for leading this diploma thesis, including useful advice and consultations. I would also like to thank ABB company, specifically Ing. Tomáš Hrycík for help and support with practical part, gained knowledge, valuable experience, and for help with formal issues and providing necessary equipment.

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List of Symbols and Abbreviations Used

A	Ampere
AC	Alternating Current
ANSI	American National Standard Institute
AVR	Automatic Voltage Regulation
BI	Binary Input
BO	Binary Output
CPU	Control Processor Unit
CT	Current Transformer
DC	Directional Current
DT	Definite Time Characteristic
GOOSE	Generic Object Oriented Substation Event
HW	Hardware
I	Current
IDMT	Inverse Definite Minimum Time characteristic
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IO	Input and Output
IT	Instrument Transformer
LD	Logical Device
LHMI	Local Human-Machine Interface
LN	Logical Node
LOF	Loss of Field
MEL	Minimum Excitation Limiter
MMF	Magnetomotive Force
MV	Medium Voltage
p.u.	per unit
PF	Power Factor
REG 630	Generator protection and control IED
RTD	Resistance Temperature Detector
SCADA	Supervisory Control and Data Acquisition
SW	Software
T&D	Transmission and Distribution
U	Voltage
V	Volt
VT	Voltage Transformer

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Introduction

The Intelligent Electronic Device (IED) is a device containing microprocessors. IED can receive data or control signals from an external source and send them to another external source. The logic nodes and context conditions define the IED functionality. Currently, IEDs are applied to many technical spheres including relaying protection.

One of the segments of the ABB industry is the production of complex IEDs for various protection applications. The product line of ABB protection, control, and supervision IED is called the Relion family. Many aspects determine the application of the ABB IED, but the most important one is the type of the protected equipment.

The REG type of IED covers the generator protection branch of the Relion family. REG 630 is a part of the 630 series of the Relion family, designed for generator protection. The REG 630 application and setting is the scope of many ABB projects now. For the best efficiency, initial training for engineers who are not familiar with this type of IED is required.

The preparation of the initial training for the REG 630 application for MV generator protection has become the scope of this thesis. The purpose of the thesis is to bring the description and solution of the initial training. The scope of the initial training is to get familiar with the REG 630 main functionalities and to acquire the ability of simple manipulations with the REG 630, such as protection setting, adjustment of the relay to power system requirements, and safe operation with the IED. The result of the thesis brings a sufficient initial training description and the complete testing example, which will form the initial training for new engineers.

The first chapter of this diploma thesis deals with the basic theoretical background for the study of the relaying protection of a generator. Three types of generator protection namely differential, earth-fault, and loss of excitation protection principles are described in detail in this chapter. The chapter ends with an explanation of the IED's role in modern protection systems.

The second chapter is an introduction to the REG 630. Also, the implementation of the protections, which were described in the previous chapter, is provided here. The information about REG 630 such as composition, control, and implementation of protection logic is overviewed in subparagraphs. Each subparagraph contains a logic scheme of the protection function block, an example of a protection zone, determined by the available parameters and equations used in the practical part.

At the beginning of the practical part, the testing panel with the REG 630 functionality and composition is described. As there is no real generator, all apparatus, such as circuit breaker, truck (disconnector), and earth switch were simulated by the testing panel logic. The tester OMICRON CMC 310 simulated the secondary values of the generator instrument transformers (IT).

The REG 630 parameters setting was done via PCM600 software provided by ABB. The fourth part of the thesis is dedicated to describing of PCM600 configuration of the REG 630 for protection testing and training purposes. The hardware modules configuration is done to set the ratio between secondary and primary current and voltage values. The application configuration is done to set up each of the protection function blocks, measurement and control functions, analog inputs, and outputs purpose for particular usage.

The last two chapters of the practical part describe the training assignment and testing itself. Each subparagraph of the fifth chapter contains sufficient information about the wiring between the tester and control panel with the REG 630, process of the testing for each of the protection types, and an explanation of protection settings. The last chapter contains the results and analysis of the protection testing. The analysis is done by the graphical comparison of the set protection operation zones and measured values.

1 Basic Information about Generators and Protection

A generator is an electrical machine, which converts the mechanical energy of a turbine to electrical energy with defined parameters. An example of a generator is shown in figure 1.

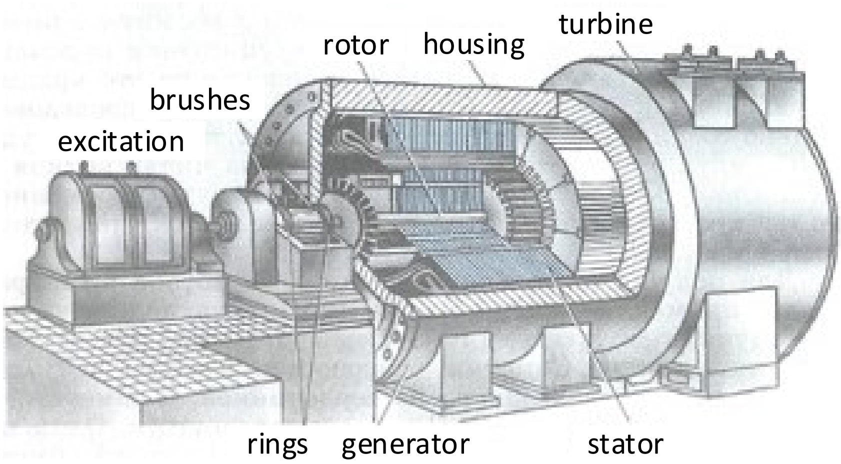


Figure 1 – The example of the generator structure

Generators classification is various and describes generators from many points, e.g.:

- By the source of mechanical energy:
  - turbo-generator.
  - hydro-generator.
  - diesel-generator.
  - wind power generator.
- By the type of output current:
  - generators of alternating current.
  - generators of direct current.
- By the number of phases:
  - three-phase generators.
  - one-phase generators.
- By the industry where the generator is applied:
  - power plants.
  - mining industry.
  - oil and gas mining.
  - paper production
  - etc.

This work is dedicated to power plant generator protection, so in further chapters where the word “generator” is used it describes the three-phase synchronous power turbo-generator, usually applied at power plants.

During the process of electrical energy production, there is a possibility of fault or disturbance occurrence.

An electrical disturbance is an occurrence, during which electrical energy has distorted parameters such as shape or amount. The consequences of distortions vary from equipment malfunction to failure. The most frequently occurred disturbances are harmonic disturbances, disturbances caused by contributing factors, disturbances caused by interruption of electricity, noises, overvoltages and undervoltages, sags, swells, and transient effects.

A fault in an electrical system is an imperfection in the electrical circuit, which deflects current from the intended part, often is accompanied by damaging or destruction of affected equipment. The types of faults are, as follows: [1]

1. Single phase-to-ground faults. Occurs because of insulation breakdown between the phase and ground. The most frequently occurred – about 70-80% of all faults in power systems.
2. Phase-to-phase to ground faults. Occurs because of insulation breakdown between two phases and ground. This type of fault takes 10-17% of all faults in power systems.
3. Phase to phase faults. Occurs when there is insulation damage between two phases. This type of faults takes 8-10% of all faults.
4. Three-phase fault. Usually the most hazardous for electrical equipment kind of fault takes 2-3% of all faults.

To protect electrical equipment from faults protective devices are used, such as fuses, relays, circuit breakers, etc.

Instrument transformers (ITs) are used to connect protection with power system. The term “instrument transformer” includes current transformers and voltage transformers.

Current transformer (CT), in which the secondary current is under normal conditions, is practically proportional to the primary current and phase-shifted from it by an angle close to zero. [2]

Voltage transformer (VT), in which the secondary voltage is under normal conditions, is practically proportional to the primary voltage and phase-shifted from it by an angle close to zero. [2]

There are two types of ITs: ITs for measuring and ITs for protection. The difference between those types is in their accuracy depending on the current level. Current transformers for protection must guarantee sufficient accuracy at current levels several times higher than rated current.

Relay protection is a complex of protective equipment including relays, circuit breakers, measurement devices, etc. The relay protection is intended to monitor the condition of the power system and automatically separate faults from the healthy parts of the system. The main facets of relay protection are:

1. Reliability ensures correct protection operation during faults and non-tripping during normal conditions.
2. Selectivity ensures correct disconnection of fault zone with maximum service continuity.
3. Sensitivity ensures protection ability to determine minimum values of operating parameters needed for relay to trip.
4. Speed of the protection acting ensures protection the fastest operating time.
5. Simplicity ensures the allowed minimum of protective equipment without negative influence on protection operation.

The basic electrical protection functionalities are divided into classification groups. Each group describes the main principle applied for the exact protection type. The main classification groups of relay protection as follows:

1. Differential protection.
2. Overcurrent protection.
3. Over- and undervoltage protections.
4. Protection against arc.
5. Distance protection.
6. High-frequency protection.
7. Impedance protection.

The generator represents a class of electric rotating machines, which is very complex, therefore, is a subject of many different types of failure. Thus, the protection of generators should cover not only electrical but also mechanical hazards. The types of generator protection are, as follows: [3]

1. Stator protection

Stator faults are the result of insulation breakdown, which leads to arc development either between phases or between a phase conductor and grounded magnetic steel. The cause of insulation breakdown might be overvoltage, thermal damage, or mechanical damage due to fault.

a. Phase fault protection

Phase faults in generators are rare, but can significantly damage stator winding. They often develop in ground faults. The standard method of protection is differential type.

b. Ground fault protection

Most of the generators' stator winding faults are ground faults. The main practice against earth-faults is an earth-fault current limitation by adding impedance in ground connection. The standard method of protection is the overcurrent type. The setting of protection depends on the grounding type.

c. Turn-to-turn protection

Turn-to-turn faults are rare, but they can have high currents and produce significant core damage. The main hazard is fire due to the oxygen cooling systems of generators, which supply an ample amount of oxygen to the fire. Since the probability of turn-to-turn fault is low, the main protection against them usually is not provided. However, there is always backup protection provided by ground fault protection, since turn-to-turn fault might develop in the ground fault.

d. Stator open circuit protection

Usually, there is no protection provided against open circuits since there is no permanent damage because of it. However, the open circuit of the stator might lead to high negative-sequence currents appearance. The alarm system should inform the power plant staff about the open circuit of the generator stator.

e. Thermal overload protection

Causes of overheating of a generator are overload, failures of the cooling system, shorted lamination of stator steel, or core bolt insulation failures in the stator steel. The temperature of stator windings is measured by temperature devices, their output can be used by temperature protection to shut down the generator.

f. Overvoltage protection

Two types of overvoltages affect the generator: overvoltage caused by transient effects due to lightning or switching surges and overvoltage because of defective generator controls. The result of overvoltage is overspeed. Due to design reasons, hydro generators are more affected by overvoltage than steam units. The protection against overvoltage is usually a complex of regulation devices and overvoltage relays.

g. Unbalanced current protection

The unbalanced current in the generator might appear because of unbalanced loading. It causes a high negative-sequence current to flow in the stator windings. Unbalanced faults cause severe heating in the synchronous machine down to rotor melting. The protection against unbalanced currents is usually the negative-sequence type relaying.

2. Rotor protection

The rotor protection consists of several protection types. Some of them allow to avoid hazards completely, others help to reduce the hazardous impact on the synchronous machine.

a. Shorted field winding protection

Shorted turns of a generator field winding distort the air gap magnetic flux. If the air gap flux is distorted badly enough, it can produce asymmetrical forces that affect the rotor. They tend the rotor to warp, in the worst-case scenario, there is a possibility of rotor and stator contact. To alarm the operator, vibration detectors are used as protection and alarming system.

b. Grounded field winding

The mechanism of the shorted winding appearance is bonded with the grounding of the winding at two different places. The single ground fault does not cause any serious impact on the generator; however, the second ground fault will cause shorted winding conditions. Thereby, generator protection should trip with the occurrence of the single ground fault to prevent tougher fault. The protection is usually implemented with voltage relaying in the exciter–field winding circuit.

c. Open field winding

Field open winding conditions are rare; however, it might lead to arcing and significant rotor steel damage. If the open circuit does not involve ground, the fault causes the reduction of excitation current and might be detected by loss of excitation protection.

d. Overheating of the field winding

The temperature of field winding is measured by an ohmmeter type of detector calibrated to temperature for direct temperature measurement. With the increasing field winding temperature, the alarming system trips.

3. Loss of excitation protection

Under normal operation of synchronous generator, the field created by the rotor windings locks in with revolving MMF of the stator windings and the rotor moves at synchronous speed with stator field, at least in the steady-state. The loss of field, when the excitation system faults, synchronism collapses, and the generator will start to consume a huge amount of reactive power from the system but will continue to supply active power. These conditions lead to voltage drop in the system with the tendency of the system voltage to collapse, generator acceleration, the severe increase of stator currents, and rotor overheating. To protect the generator and the system against the loss of excitation consequences the mho type of distance relay is used.

4. Other generator protection systems

There are also other protection systems, which protect not the stator and the rotor of the generator, but the generator itself. Some of them are described below.

a. Overspeed protection

As discussed before, overvoltage causes overspeed of the turbine-generator unit. The overvoltage relays are used to protect the generator against overspeed; however, the turbine always has the control system to adjust speed under current conditions in the power system. The protection must be selective and must not shut the unit down during temporary external faults, but should operate if the fault occurs at the protected zone.

b. Under- and over frequency protections

The under- and over frequency protection is used to protect the generator against frequency fluctuations, which may appear if the turbine speed changes over rated value.

c. Motoring protection

Motoring is not harmful to the generator in any way, thus motoring protection is a part of the turbine protection system. Nevertheless, the protection is usually considered as a part of generator protection since it uses electrical quantities for operation. When the steam supply (or water supply for hydro turbines) is interrupted, it causes the overheating of turbine blades, which can damage blades themselves or other parts of the turbine. If protection is required, power and inverse power relays are used.

d. Vibration protection

Vibration protection is also a part of turbine protection. Nonetheless, it is backup protection against rotor faults, so this is important to have the coordination between electrical protection and mechanical vibration protection. The normal situation is when the vibration detector is connected to the alarm system and can manipulate the time-delayed trip of the generator and field breakers.

e. Bearing failure protection

If fault current goes through the generator bearing, it causes the corrosion of metal parts of bearing. The bearing failure protection is implemented by temperature control of bearing itself or oil of bearing if the bearing has it as a lubricant. The output of the temperature measuring device can be used to alarm the operator or, in some cases, to trip unit protection.

f. Coolant failure protection

Some of the larger generators have water-cooling systems. To protect the generator against cooling system failure, flow detectors are placed in cooling water. They are used to alarm the operator and operate the backup pumps of cooling systems.

g. Fire protection

Fire protection is usually achieved by using special equipment to quickly extinguish the fire in the generator housing. If the generator has an air-cooling system, water or carbon dioxide can be supplied by a fire extinguishing system to put out the fire. If the generator has a hydrogen cooling system, no fire protection is required, however, the hydrogen purity must be monitored.

The generator protection is complex and difficult. In this diploma thesis, only three types of protection are chosen to be tested. The selection was carried out with the following criteria:

1. The difficulty of adjustment.
2. The practical benefits.
3. The opportunity of proper simulation with available equipment.

The following protections were chosen to be tested during training completion:

1. Differential protection of the generator.
2. Earth-fault protection of the generator.
3. Loss of excitation protection of the generator.

1.1 Differential Protection Principles

1.1.1 The Theoretical Basis of Differential Protection

The differential protection principle is based on the comparison of input and output currents to the protected zone. Not only the magnitude of currents might be compared but also the angles between them. If the difference between currents exceeds the set limits, protection must trip. This protection principle is applicable only if the physical distance between both ends of the apparatus is respectively small, e.g. transformer protection, busbar protection, or generator protection.

The simplest form of differential protection is provided by an instantaneous relay connected as shown in figure 2. [1]

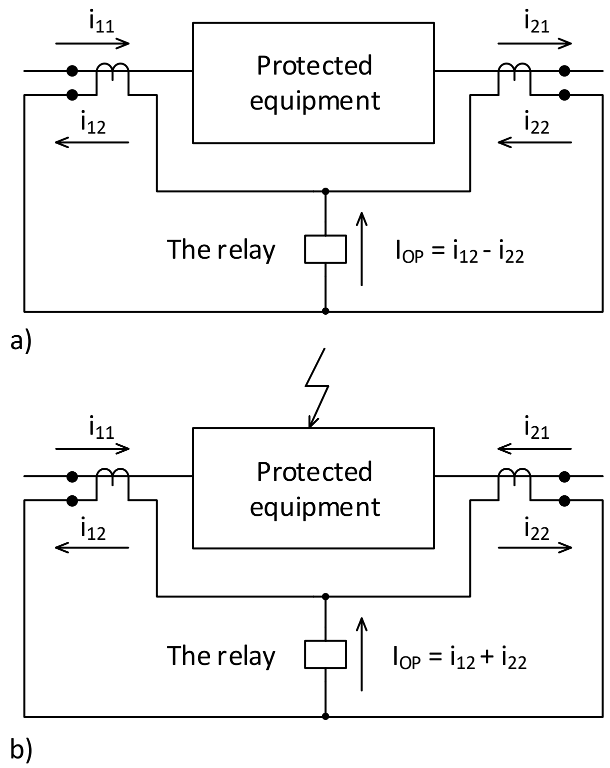


Figure 2 – The differential protection principle

a) Operation without fault or during external fault; b) Operation during internal fault

Generally, differential (or operation) current can be calculated by the following equation:

$$I_{OP} = |\overrightarrow{\iota_{12}} + \overrightarrow{\iota_{22}}| \qquad [1]$$

I_{OP}… is the operation current of the relay
i_{12}… is the second input current
i_{22}… is the secondary output current

For the normal operation mode and all external faults, the differential current I_{OP} is the difference in currents i_{12} and i_{22}. Assuming that conditions are ideal, CTs will be completely equal, currents i_{12} and i_{22} will be equal to the corresponding excitation current of a CT, and relay operating current I_{OP} will be zero. However, in practice, even the same CTs have slightly different ratio and angle errors, thus secondary currents i_{12} and i_{22} will be less than exciting currents of CTs. The error current equals the difference of two exciting currents that will flow through the relay during normal operation mode. [1] [4] [5]

During external faults and assuming ideal conditions, there is no difference between input and output current, thus, the operation current I_{OP} equals zero as in the normal operation mode. In practice, the large transient-operating currents might appear due to CT transient performance. The false operation of relay is avoided by using the time-delay relays and correct relay setting for the network requirements. [1] [5]

The actual vector diagram for differential protection scheme during external fault is shown in figure 3.

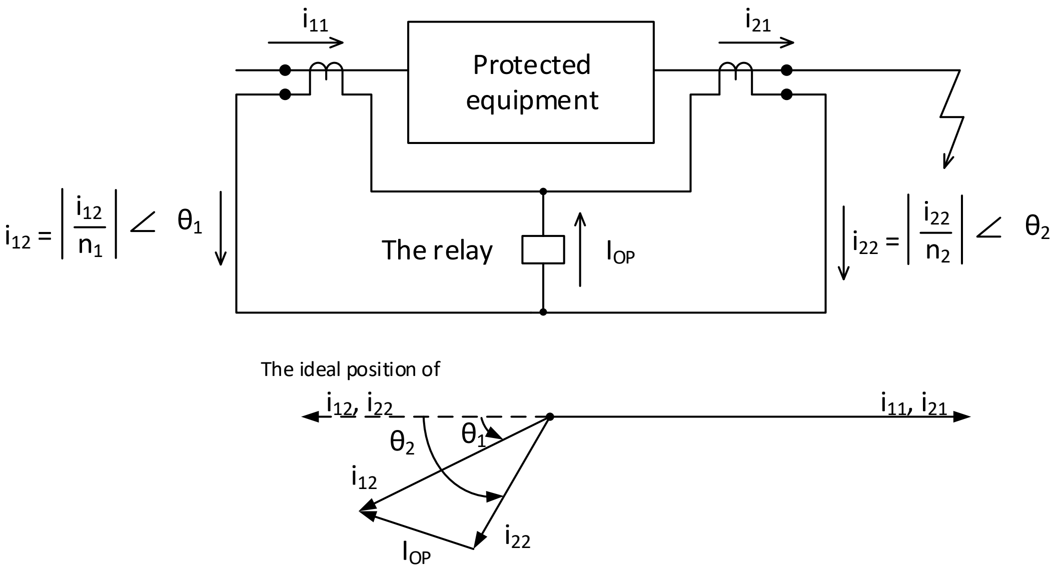


Figure 3 – The vector diagram for differential protection scheme during external fault [4]

In a real situation, CTs have different ratios n_1 and n_2 and different angle errors θ_1 and θ_2, which causes the operational current I_{OP}.

During the internal fault, one of the currents (i_{22} in our case) will change its direction to the opposite, as shown in Figure 2b. Thus, since the angle difference between secondary currents is 0°, the operating current I_{OP} will be the sum of i_{12} and i_{22}. The protection must trip.

1.1.2 The Characteristics of Differential Relays

There are two basic characteristics of the differential relay. The simple characteristic is described by low stability and risk of malfunction during external fault. The type of characteristic is the horizontal line. An example of a simple horizontal characteristic is shown in figure 4.

With the increase of current during the external fault, various imperfections between CTs are starting to magnify. Eventually, the differential current in the relay will exceed the set limit (I_{lim} in Figure 4) and the relay will trip despite the fault is external. The current that causes the relay malfunction is called the fault stability limit. Beyond this limit, the protection system loses its stability. Otherwise, with some very light internal faults, the simple differential relay might not trip.

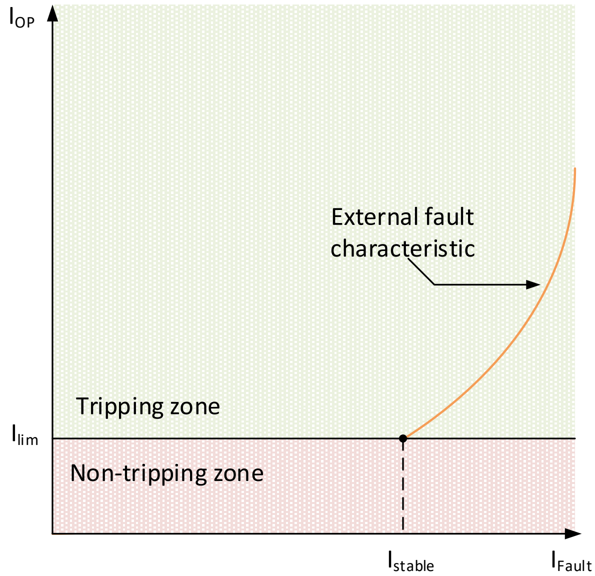


Figure 4 – The characteristic of the simple differential relay [4]

To increase the stability for external faults and provide high selectivity for all types of internal faults, a percentage type of the differential relay is used. The percentage type of the relay was developed to overcome the shortcomings of the real protection scheme. The relay has not only the operating winding but also restraint winding, as shown in figure 5.

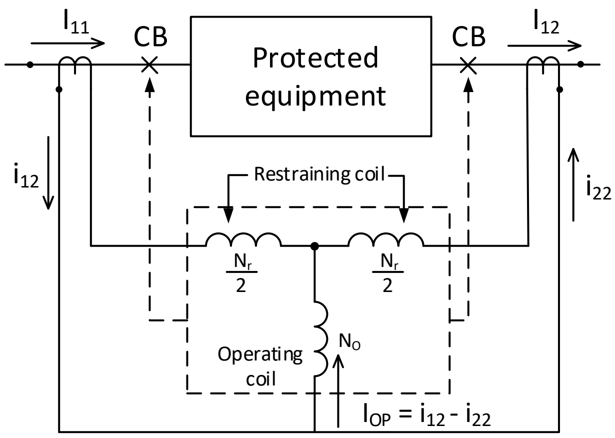


Figure 5 – The scheme of the differential relay with restraint wiring

The operation principle of the operation relay is that current in the restraint winding produces contact opening torque; current in the operating winding produces contact closing torque. When the operating current exceeds the restraint current by a given percentage the relay will trip. The restraint winding provides an automatic increase of current in the operating coil to trip as fault current and the resulting error in CT increase. Restraint current might be also called bias or stabilized and can be determined by the following equation: [6]

$$I_{bias} = \left|\frac{\overrightarrow{I_1} - \overrightarrow{I_2}}{2}\right| \quad [2]$$

I_{bias}... is the bias (restraint) current
I_1... is the secondary current of the CT from the line side
I_2... is the secondary current of the CT from the generator side

Usually, the electromechanical relays have a non-adjustable slope of 10%, 25%, 40%, or 50% incline defined by the manufacturer. An example of electromechanical relay characteristic with 50% slope and variable characteristic is shown in figure 6. The relay characteristic includes minimum operating current. This current describes the maximum sensitivity for the generator fault while the generator is disconnected from the power system.

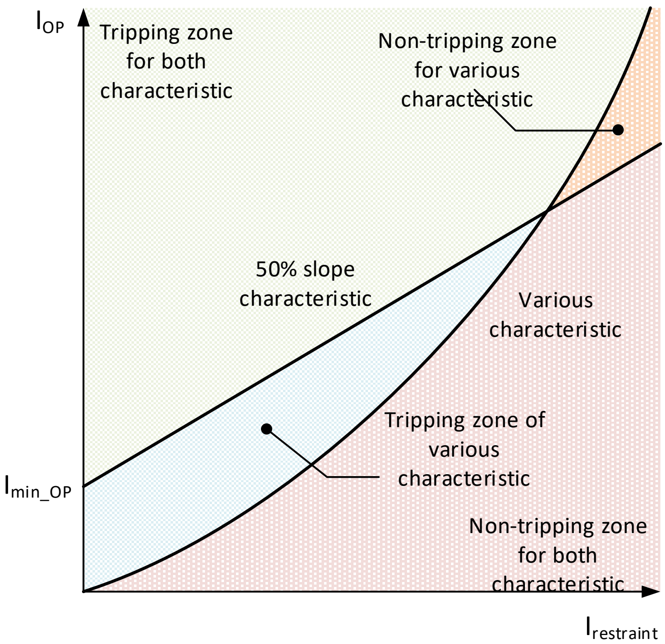


Figure 6 – The example of 50% slope characteristic and various characteristic of the electromechanical relay

The solid-state and microprocessor relays usually have adjustable characteristics. The typical part of characteristic are minimum operating current, slope 1 characteristic to avoid malfunction during external fault and slope 2 defines the instantaneous stage of protection. The example of the microprocessor relay characteristic is shown in figure 7.

Both types of relays are applicable for generator protection. However, nowadays solid-state microprocessor relaying is preferable due to the complex protection of generators.

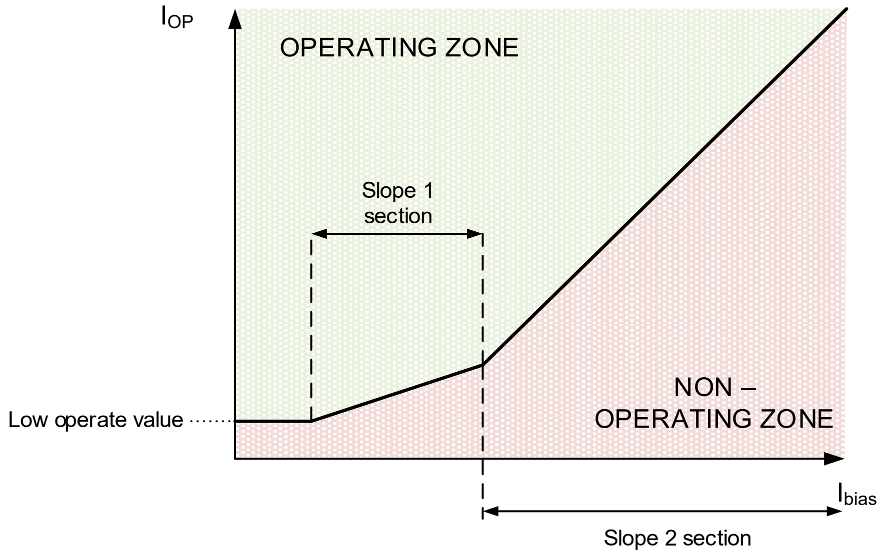


Figure 7 – An example of microprocessor relay characteristic

1.2 Ground Fault Protection of a Generator

Ground fault in a generator is a hazardous event that occurred because of insulation breakdown between stator windings and grounding network. The cause of insulation breakdown is aging with vibration damage. A ground fault may occur initially, or other faults can develop into the ground fault, e.g. turn-to-turn fault.

The main hazard of the ground fault is stator damage. The severity of damage depends on the character of fault: either fault current is conducted from faulted coil and core direct contact or the arcing. The second fault type is much more hazardous due to the arc concentrating the fault energy at one point of the core.

1.2.1 Types of Generator Grounding Systems

There are several types of grounding systems distinguished: [5]

1. Ungrounded system.
2. Effectively grounded system.
3. Low-impedance grounded.
4. High-impedance grounded.

The listed above types of generator grounding might be subdivided into several subgroups based on the impedance exact value or impedance character (inductance grounding, resistance grounding, or resonant grounding). However, these types are basic.

Despite the fact that there is no direct connection between generator neutral and ground, there is a small ground-fault current during short-circuit conditions because of a shunt system capacitance.

With an effectively grounded system, there is a high phase-to-ground fault current during short-circuit due to direct connection between ground and generator neutral node. In some cases, a phase-to-ground fault current might be higher than a three-phase short-circuit current.

With a low-impedance grounding system, there is a minimal impedance in the generator neutral and ground connection. This allows setting a limit of phase-to-ground fault value typically between 100A and the magnitude of three-phase short-circuit current.

With a high-impedance grounding system, the value of impedance in the generator neutral and ground connection allows restricting the value of phase-to-ground current between 2A and 15A.

Current practice excludes ungrounded operation, but other methods of grounding are used. In some cases, the ungrounded application is still used, e.g. in systems, where an uninterruptable power supply is required. [5]

1.2.2 Types of Ground Fault Protection

The type of implemented grounding and the system configuration determine the choice of protective scheme.

The next types of ground fault protection are distinguished: [5] [7]

1. High-impedance grounding protection schemes:
    a. Neutral overvoltage protection scheme.
    b. Overcurrent scheme.
2. Low-impedance grounding protection schemes:
    a. Ground differential protection scheme.
3. 100% stator protection schemes:
    a. Third-harmonic undervoltage scheme.
    b. Third-harmonic overvoltage scheme.
    c. Neutral injection scheme.

With **the high-impedance grounding system**, the fault current is typically restricted with a 10A value. However, if the second ground fault appears the fault current will increase and cause severe damage to stator windings. Therefore, high-impedance grounding system protections always have alarming systems for ground faults and time-delayed operation functions.

A neutral overvoltage protection scheme is the most commonly used unit protection with a high-impedance grounding system. Protection is provided by connecting a sensitive overvoltage relay with IDMT characteristic in parallel with the grounding resistance or reactor at the secondary winding of the grounding transformer. The relay indicates the zero-sequence voltage V_0. The example of the protection scheme is shown in figure 8. The 59GN relay is usually applicable for this type of protection scheme. [8]

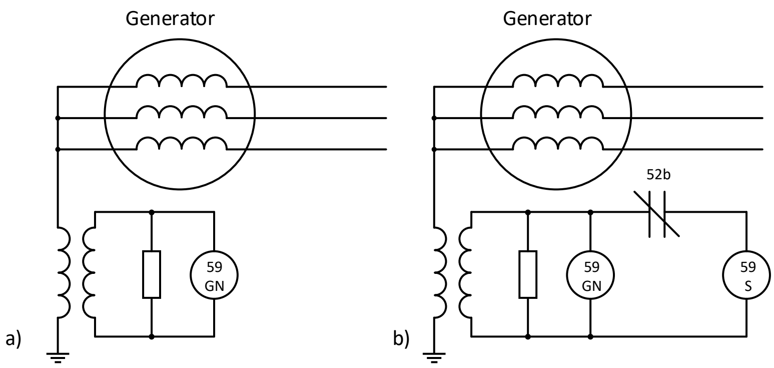


Figure 8 – An example of neutral overvoltage scheme; a) Simple overvoltage scheme; b) Presynchronizing overvoltage scheme

The presynchronization of the relay is used to reduce the time delay during operation and increase the sensitivity of protection during the start-up of a generator and other off-normal frequency operating conditions.

The overcurrent protection schemes are applied to a high-impedance grounding system either residually with the overvoltage protection or as independent protection. Figure 9 illustrates an example of an overcurrent protection application.

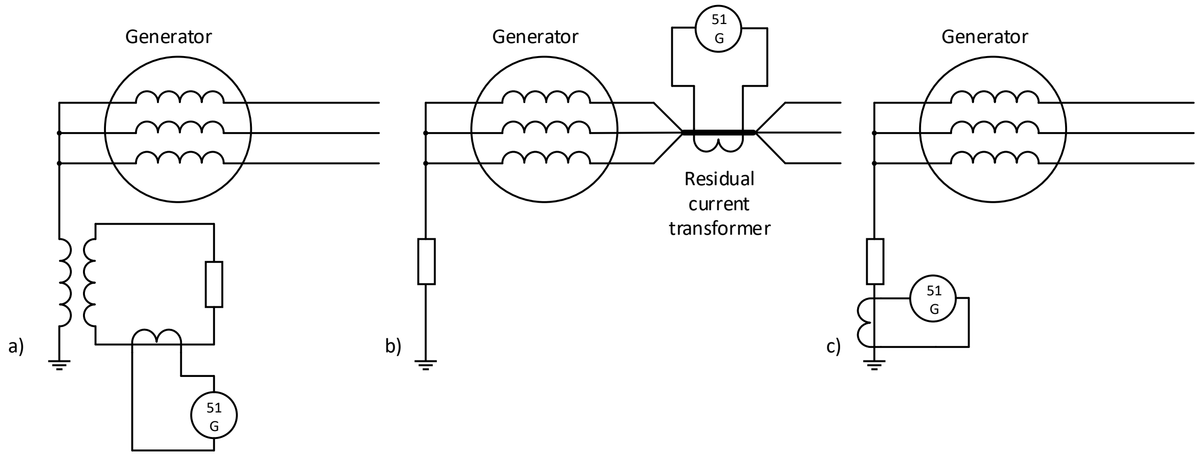


Figure 9 – The ground overcurrent schemes; a) Back up of overvoltage scheme; b) The overcurrent scheme with window type CT; c) Simple overcurrent scheme

Case (a) represents the backup for the neutral overvoltage protection scheme. The 51G type relay is usually used for this type of protection scheme. [8]

In case (b), all three-phase conductors pass through one window type CT. The secondary CT current represents $3I_0$. The application of this scheme is limited with the size of the generator, and the size of the ground-fault current. If the ground fault current is significant, the relay might be inoperative. The 51G type relay is usually used for this type of protection scheme. [8]

The (c) case represents an example of an independent overcurrent protection scheme.

The low-impedance grounding system typically sets the ground fault current limits between 100A and the three-phase fault current magnitude. Thus, overcurrent protection is applicable. The configuration of the protection scheme is determined by the set limits for ground fault. At the low-end fault current limit the overcurrent protection schemes are applicable as shown in Figure 9.

The ground differential protection schemes are applicable to provide supplemental protection on low-impedance grounded systems. The applicable schemes are shown in figure 10.

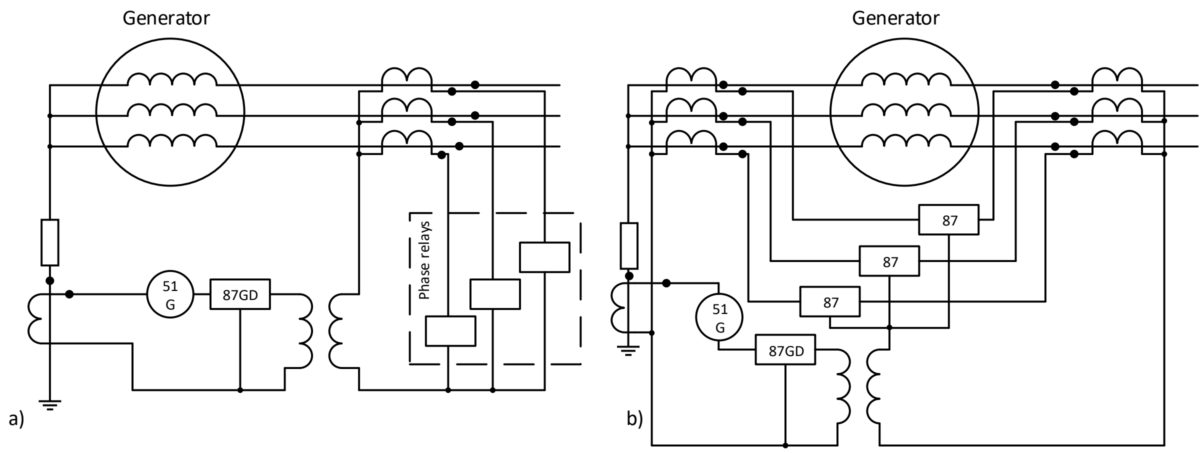


Figure 10 – The ground differential protection schemes; a) Zero-sequence differential protection with directional overcurrent relay; b) Differential zero-sequence protection with directional overcurrent relay synchronized with generator differential protection

Both schemes are applicable where increased sensitivity is required or to provide selectivity in a situation when several units are connected to the common busbar. The directional overcurrent 51G type relay is typically used with an 87GD type relay. [8]

The above-mentioned protections can detect the fault over 95% of the winding. The rest 5% of faults are located too close to the neutral point to be detected. The danger of these faults is that they bypass the ground fault protection, and if the second fault will occur in the same phase near the generator terminals, it will remain undetected. This will be detected by differential protection of the generator only when it will develop into a phase-to-phase fault. As a result of these considerations, **100% stator protection schemes** are now available. Generally, there are two categories of protection schemes: third-harmonic voltage schemes and neutral injection schemes.

The principle of **third-harmonic voltage protection schemes** is based on the detection of third harmonic voltages produced by a generator. The so-called triplen harmonics (3^{rd}, 9^{th}, 21^{st}, etc.) have the most significant influence on the produces by generator energy. Since those harmonics are in phase, their sum is not equal to zero and their presence causes the zero-sequence quantities in the neutral circuit. Figure 11 illustrates the distribution of third-harmonic voltage during normal conditions and faults.

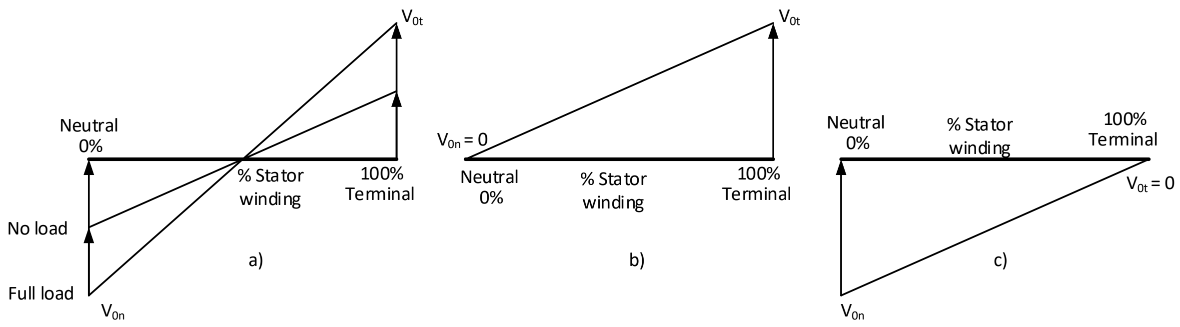


Figure 11 – The distribution of third-harmonic voltages over stator winding during: a) Normal operation; b) Ground-fault at the generator neutral; c) Ground-fault at the generator terminal

The third-harmonic protection schemes are presented in figure 12.

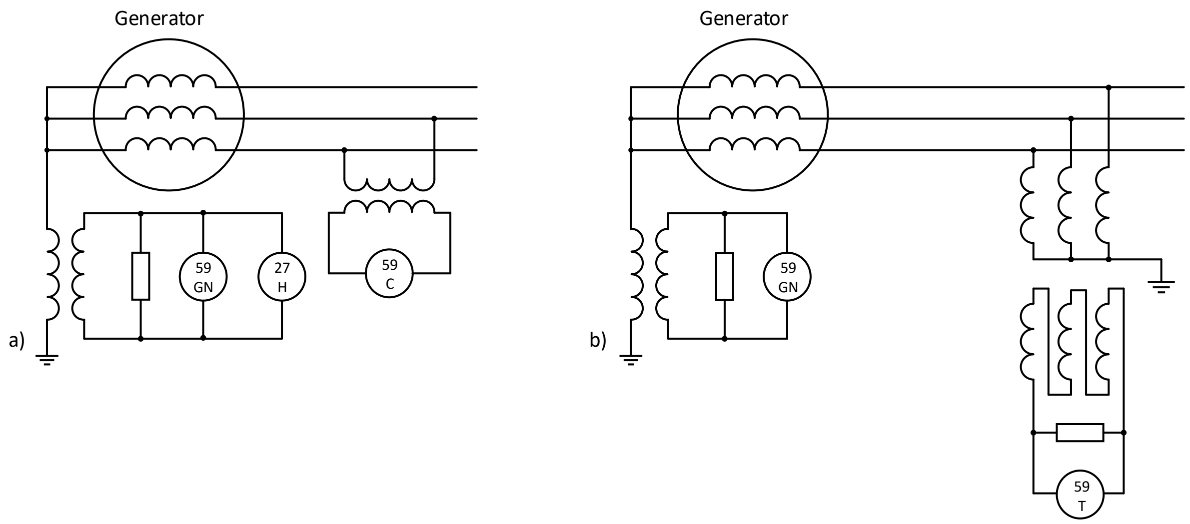


Figure 12 – The third-harmonic voltage protection schemes; a) Undervoltage scheme; b) Overvoltage scheme [7]

The (a) scheme is based on a 27H undervoltage relay tuned to third-harmonics 150 Hz and 59GN over-voltage relay tuned to nominal frequency 50 Hz. Stator fault occurred at the generator terminals zone produce significant zero-sequence voltages for 59GN relay to operate. Ground fault near the neutral point causes the third-harmonic voltage for the 27H relay to operate. 59C Time-delay overvoltage relay is used to block 27H during generator start-up.

The (b) scheme operation principle is the same as for (a). The broken-delta VT is used to detect zero-sequence voltages at the generator terminals. The broken-delta connection imposes the voltage for relay operation to $3V_0$ value. The 59T overvoltage relay is tuned to third-harmonic frequency 150 Hz and operates as third-harmonic voltage increases in the generator terminal zone during ground fault near the neutral.

Other third-harmonic schemes are also applicable. The decision of which scheme to apply depends on the size of the generator unit, power system requirements. Other schemes are covered by standards and recommendations. [7]

The neutral injection scheme is applicable for 100% stator protection in situations when it is impossible to apply a third-harmonic protection scheme due to power system requirements or generator design. The overview of the neutral injection scheme is presented in figure 13.

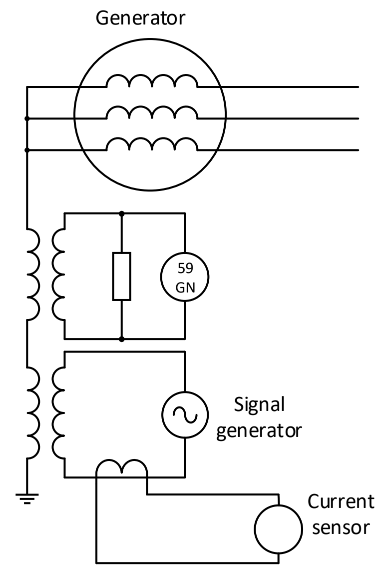


Figure 13 – The neutral injection scheme

The AC voltage signal generator is connected to a secondary side of the injection transformer mounted in series with a grounding transformer. The produced signal has subnominal frequency to provide increased security and sensitivity. The resulted subnominal frequency current is determined by the impedance of the transformers in the neutral circuit and the shunt capacitance of the stator circuit. During a ground fault, the fault current bypass the capacitance and increases the trip current.

1.3 Loss of Excitation Protection of a Generator

Loss of excitation or loss of field (LOF) occurs when the excitation of the generator field wining fails. The typical causes of LOF are: [9]

1. Failures in the excitation system of a generator, e.g. open or short-circuit.
2. Field circuit breaker failures.
3. Arcing at the slip ring of a generator.
4. Loss of AC or DC supply to the excitation system.

The excitation system of a generator provides current to field winding. This, in turn, excites the rotor magnetic circuit to produce rotor flux. This flux generates an internal voltage of a generator, which is opposite to system voltage. When the loss of excitation occurs, the rotor current decays proportionally with the field circuit time constant. The internal generator voltage drops at the same rate as the rotor current. As a result, the reactive power output of a generator drops below zero and a generator starts consuming reactive power from the attached system, which causes a significant voltage drop in the part of the power system close to the generator with field loss. The internal voltage drop also reduces the magnetic coupling between the rotor and stator, which leads to synchronism loss.

1.3.1 Types of Damage During a Loss of Excitation

LOF conditions have an impact on the generator and the system generator is connected with. The next possible types of damage may occur because of LOF:

1. System impact:
    a. Severe voltage degradation in the system.
2. Generator damage:
    a. Stator winding overload.
    b. Stator end-core damage.
    c. Rotor damage.
    d. Torque pulsations.

The reasons for **system voltage degradation** are described above.

The stator winding overload is caused by the large consumption of reactive power from the system and depressing voltage on the generator terminals. The range of stator winding current during LOF is varying between 1.13 and 2.13 of the nominal current.

The damage of the stator end-core is typical for cylindrical rotor machines, where the ends of the stator core are operated under reduced field current. This causes excessive end-core heating, which can damage the insulation of stator winding.

The rotor damage occurs as a result of overheating caused by high currents induced in the rotor winding. During a loss of excitation event, rotor velocity frequency differs from stator field velocity by the slip frequency, which causes the potential damaging of rotor structures.

The torque pulsations are the result of electrical and magnetic differences of the d- and q-axes of the rotor. The torque pulsation causes stress to the generator and the prime mover.

1.3.2 The Capability Curves of a Synchronous Generator and mho Characteristic

Capability curves represent a generator characteristic, which describes boundaries the generator can safely operate within. Typical capability curves characteristic is shown in figure 14.

In Figure 14, the safe operating zone of a generator is limited by the ABCD curve. AB is the field current limit, BC is the stator current limit, CD is the heating limit for the stator end-core. Point H is a possible location of the C point. BH instead of BC is a possible active power limit due to turbine output power limitation. EF is the steady-state limit for generators without AVR.

The generator-rated operation zone is between B and C points. If the generator power factor falls below the rated value in the lagging direction (AB curve), the generator produces an excess value of reactive power, which requires significant field currents. If the generator power factor falls below the rated value in the leading area (CD curve), the significant heating of the stator end-core occurs.

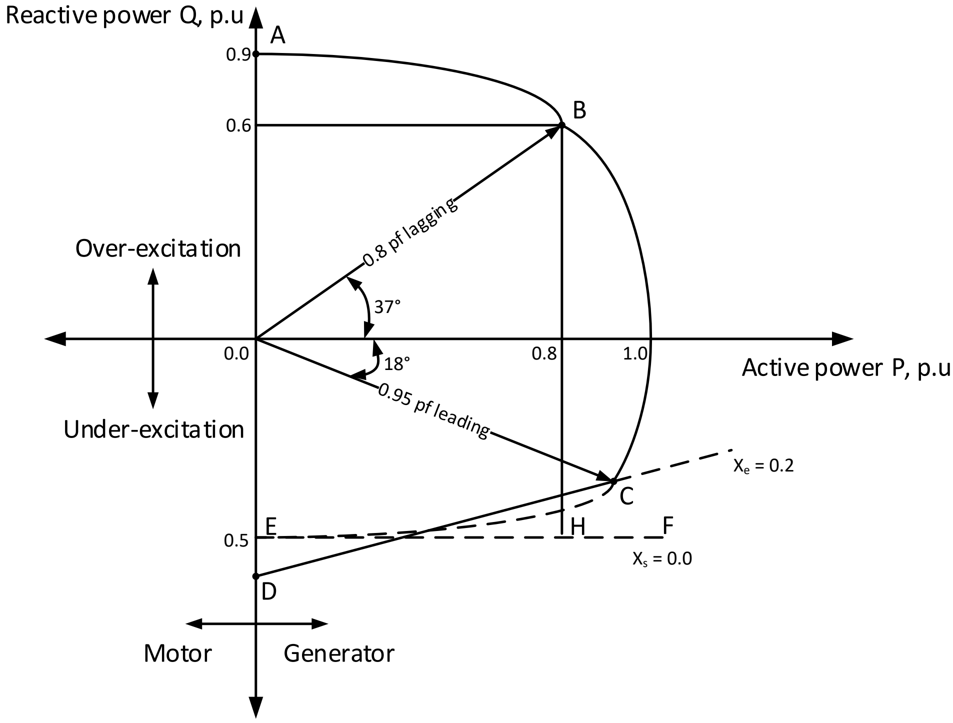


Figure 14 – Typical capability curves characteristic of a generator

Capability curves of a generator are used to build a mho characteristic for relaying protection of a generator against loss of excitation.

Mho characteristic is a threshold characteristic in the impedance plane of distance relay that shows the area where relay should trip. Typical mho characteristic of 40 distance relay is shown in figure 15.

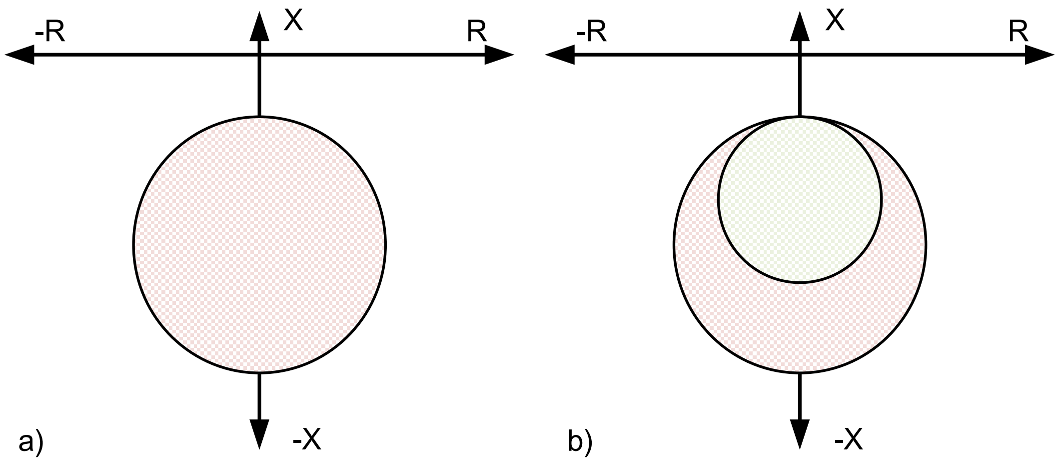


Figure 15 – The typical mho characteristic of a distance relay; a) A single mho relay characteristic; b) The typical characteristic of two mho relays

The capability curves of the generator can be transformed from the P-Q plane to the R-X or impedance plane. For each point of the curve, the value of apparent power is known and angle β can be determined as the angle between the P-axis and power vector of the exact point. The impedance representation of capability curve point is calculated by the following equation [9]

$$Z = \frac{U_{nom}^2}{S_{point}} \cdot \frac{R_c}{R_v} \qquad [3]$$

Z … is the calculated impedance value of the capability curve point [Ohm]
U_{nom}… is the nominal phase-to-phase voltage [MVA]
S_{point}… is the apparent power of the capability curve point [MVA]
R_C, R_V… are the CT and VT ratios [p.u.]

The mho characteristic of the distance relay implementing the underexcitation protection should be set up with the relation to generator capability curves and MEL curves. The relay should operate only during LOF conditions.

To set up the distance relay under requirements, the next values are needed:

1. The center of mho characteristic circle.
2. The offset from R-axis.
3. The radius of mho characteristic circle.

Next equations might be used to obtain the needed parameters:

$$Center = \frac{-j(X_d - X_s)}{2} \qquad [4]$$

X_d... is the synchronous unsaturated reactance of a generator
X_s... is the system impedance

$$Radius = \frac{X_d + X_s}{2} \qquad [5]$$

X_d... is the synchronous unsaturated reactance of a generator
X_s... is the system impedance

The offset of mho characteristic from the R-axis is usually equated to half of the transient reactance of a generator.

1.3.3 The Protection of a Generator Against Loss of Excitation

The protection against loss of excitation in a generator is represented by distance relay schemes.

There are two basic impedance schemes applied for LOF protection: [5]

- Protection operation is required whenever the loss of excitation conditions appear.
- Protection operation required only when there is a threat to the power system.

Both schemes' default operation has a time delay. The time delay is used to give a chance to regulators, manual or automatic ones, to restore the excitation in the generator. If the connected system is strong, a time delay can reach several minutes.

The first scheme requires a single mho device connected at the generator terminals setup to measure the impedance from generator output values and trip with the delay. To improve the scheme with the two time-delays operation, a second mho device can be applied to operate during the most severe loss of excitation events. Typically, the second mho characteristic lays inside the first one as shown in Figure 15b).

The second scheme might be applied in only one case – if the connected system is strong enough to supply the generator with the loss of excitation with required reactive power without significant voltage drop. The one distance relay is typically used with an alarming system, but for scheme improvement, the second mho device might be added in case the immediate protection operation is required during heavy LOF conditions.

The 40 distance relay is the usual implementation of loss of excitation protection. [8]

1.4 Intelligent Electronic Devices in the Relaying Protection

Generally, there are four generations of relaying protection over the years: [1] [3] [9]

1. Electromechanical relaying protection.
2. Discrete solid-state relays (static relays).
3. Rack-mounted integrated solid-state relaying protection.
4. Digital and numerical microprocessor-based relaying protection.

Electromechanical relay uses electrical quantities to operate the mechanical parts of itself. The protection is implemented by the interconnection of mechanical parts of the relay and other equipment, e.g. circuit breakers.

A static relay is a relay without moving elements, i.e. the relay response is developed by electronic, solid-state, magnetic, or other components.

A rack-mounted solid state relay is a modular device packaged for multiply protection functions. The operation principle is the same as for static relays.

A digital relay is an electronic device, which converts analog inputs into binary (square-wave) voltages. The logic of the relay compares binary voltages with setup and then decides to operate. Numerical relays convert input parameters into numeric data. The microprocessor then performs mathematical and logic operations to make trip decisions.

Intelligent electronic devices combine protection, control, measurement, and supervision functions into one device. Typical IED has a combination of several digital numerical relays to perform over 10 protection functions, 5-8 control functions for control and supervision of several separate apparatus, self-monitoring function, and communication functionality.

The complexity of the IED allows a combination of protection, measurement, control, and supervision function in one device. The next advantages are obtainable by using IED:

1. Reduction of space required for protection, measuring, control, and supervision devices.
2. Improvement of operation of primary equipment.
3. Improved usability of protection, control, and supervision functions.
4. Ease of communication between protection devices, hence the increased ease of protection setting.

2 Introduction to ABB IED

2.1 Relion Family

Relion product family is a branch of IED produced by ABB and Hitachi ABB intended for application over a wide range of power systems. Figure 16 shows an IED distribution between ABB and Hitachi ABB.

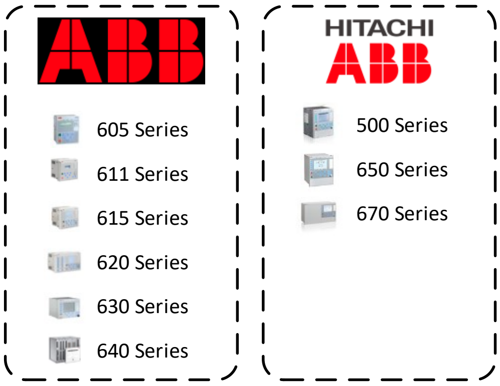


Figure 16 – Distribution of Relion products between ABB and Hitachi ABB

Each IED is designed for a particular application. The designation of IED is shown via the last letter in the device naming. Figure 17 illustrates how the naming of the Relion device is done.

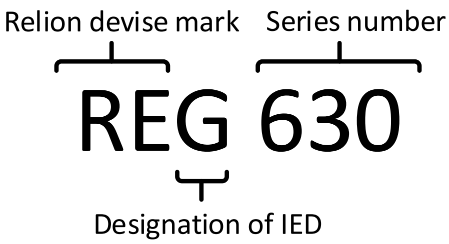


Figure 17 – The description of the Relion IED naming

Table 1 shows possible variants of Relion products names. Not every application is available for each series. The full list of available devices is determined by the manufacturer. [10]

Table 1 – Relion family types available

Application	Naming
Feeder protection	REF
Bay Control	REC
Transformer protection	RET
Line distance protection	REL
Line differential protection	RED
Motor protection	REM
Generator Protection	REG
Busbar protection	REB
Capacitance bank protection	REV
Voltage protection	REU
Current protection	REJ
Load-shedding	PML

Application	Naming
Feeder automation	RER
Wide area protection	RES
Breaker protection	REQ
Railway application	RER
Multiapplication protection	REX

2.2 Selection of ABB IED REG 630

ABB IED REG 630 is a device for small and medium-size generator protection applications. This device was chosen as a training object due to next reasons:

1. The relative novelty of the IED.
2. IED application for generator protection.
3. Absence of initial training for this particular IED.
4. The current project work requires people familiar with the generator protection systems.

In comparison with older and well-known Relion series, e.g. 615 and 620, REG 630 has some significant differences in protection setting procedure. Special knowledge is required for the proper protection setting of REG 630. Initial training will provide the required basis for correct interaction with the IED.

Generator application of the REG 630 is also a reason why this particular IED was chosen to be an object of initial training. The setting up of generator protection differs from the setting of line or feeder protection. Some protection function blocks with the same name as in the RET 615 or REF 620 might have other settings required for generator protection. The initial training for REG 630 will provide the steps required for setting up generator protection specifically.

In the first chapter of this diploma thesis, three types of generator protection were described: differential protection, earth-fault protection, and loss of excitation protection namely. In the next chapters, the REG 630 composition and exact implementation of described protections are reviewed.

2.3 The Composition of the REG 630

The IED composition depends on requirements. The number and type of hardware modules and software of each IED are defined by ordering code. The IED rated parameters are described in table 2.

Generally, each IED has a power supply module, analog inputs, and output modules, binary input and output modules, resistance temperature detectors, CPU and communication module, and integrated or detached LHMI.

Table 2 – Rated parameters of the REG 630

The name of the IED module	Quantity, parameters, or type
Communication and CPU module	Ethernet 100Base (RJ-45), Serial glass fiber
Auxiliary power / binary output module	48 – 125 VDC Power supply module
Analog input module	7 Current inputs, 3 Voltage inputs
Binary input and output module	23 BI + 18 BO
RTD input and mA output module	8 RTD-inputs and 4 outputs
LHMI	Integrated LHMI

The REG 630 is illustrated in figure 18.

Figure 18 – The appearance of the REG 630, front view

The first block (1) is control buttons for operation with the LHMI. The second block (2) is the LHMI itself. LHMI is built in the REG 630 for interaction with the function blocks settings, for measurement and control visualization. The third block (3) is fifteen programmable LEDs for user-defined purposes. The fourth block (4) is programmable buttons for user-defined purposes, the most common use is to update the protection operation statuses. The fifth block (5) is the indication block. “Ready” LED indicates the REG 630 status for operation, “Start” LED indicates that one of protection blocks started to operate, “Trip” LED indicates the protection operation.

2.4 The Implementation of Protection and Control Functions

The IED setup and interconnection with other IEDs and SCADA systems are available via GOOSE communication and described by the supported communication protocols. [11]

To adjust the IED functionality for required operation, the PCM600 software with ABB connectivity packages is used. PCM600 is a protection and control management software provided by ABB, which allows the setup of required IED functions and establishes communication with other IEDs. A connectivity package is a package of settings that are necessary for the particular IED configuration. The connectivity package version should meet the product version. In this diploma thesis, used REG 630 product version is 1.3.0, connectivity package version is 1.3.0.

The configuration of IED functionality is represented by function blocks in PCM600. Despite the fact that there are more than 80 function blocks available for REG 630, in further chapters, only crucial function blocks, such as control, measurements, and protection function blocks, will be considered.

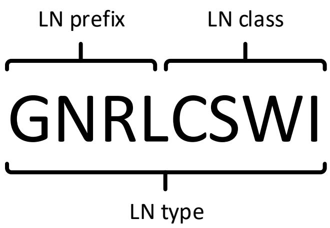
2.4.1 The Naming of Function Blocks

The naming of function blocks is done according to actual standards. [12]

Generally, the function block name consists of three parts: the device class name, LN-Prefix (optionally), and LN-Instance-ID (optionally). The example of naming structure is presented in figure 19.

[LN-Prefix] [LN class name] [LN-Instance-ID]

a)



b)

Figure 19 – The naming of function blocks; a) General principle; b) Example of naming on the Switch control function block [12] [13]

LN-Prefix should consist of m characters (optional application), starting with an alpha character. LN class name should consist of four alpha characters, in upper case. LN-Instance-ID should consist of n numeric characters (optional application). The sum of m and n should be less than or equal to twelve characters. [12]

2.4.2 Control Function Blocks

The apparatus control function in REG 630 is implemented using SCILO, GNRLCSWI, DAXSWI, and DAXCBR function blocks. The design of the listed above function blocks is illustrated in figure 20.

The combination of these four function blocks allows setting up control over the circuit breaker, earthing switch, and neutral ground resistor.

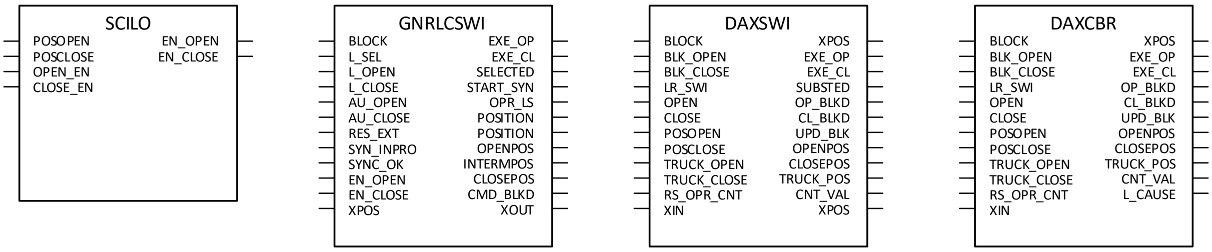


Figure 20 – The SCILO, GNRLCSWI, and DAXSWI function blocks [6]

The functions SCILO, GNRLCSWI, and DAXCBR are used to provide circuit breaker control. The SCILO function checks the interlocking conditions and provides closing and opening enabling signals to the GNRLCSWI function. The GNRLCSWI function checks the enabling signal with the operator place selector before providing the final open or close signal to the DAXCBR.

The functions SCILO, GNRLCSWI, and DAXSWI are used to provide control to earthing switch or neutral grounding resistor switch. The interconnection of function blocks is the same as for circuit breaker control, the DAXSWI function is used instead of the DAXCBR.

2.4.3 Measurement Function Blocks

The measurement function blocks allow identifying energy parameters and then using them for the operation of protection function blocks. The table 3 shows the name of the function and its purpose.

Table 3 – Measurement blocks available for the REG 630

Function block name [11]	**Description of the measured value**
CMMXU	Three-phase current measurement
VPHMMXU	Three-phase voltage measurement
VPPMMXU	Three phase-to-phase voltage measurement
RESCMMXU	Residual current measurement
RESVMMXU	Residual voltage measurement
CSMSQI	Phase sequence current measurement
VSMSQI	Phase sequence voltage measurement
PWRMMXU	Three-phase power measurement

Function blocks A1RADR, A2RADR, B1RBDR, and B2RBDR are used for disturbance recording. Functions A1RADR and A2RADR record the values of energy parameters during abnormal conditions, functions B1RBDR and B2RBDR record the protection operation.

2.4.4 Differential Protection Function Block

The generator differential protection is implemented in REG 630 by the MPDIF function block. The design of the function block is illustrated in figure 21.

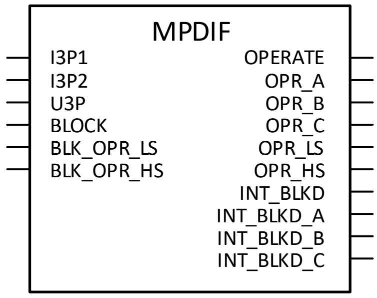


Figure 21 – The MPDIF function block [6]

The input signals I3P1, I3P2, and U3P are three-phase group signals of currents from the line side, currents from the generator side, and voltage at generator terminals respectively. The module diagram presented in figure 22 represents the calculation of output signals later used for protection operation and block functions.

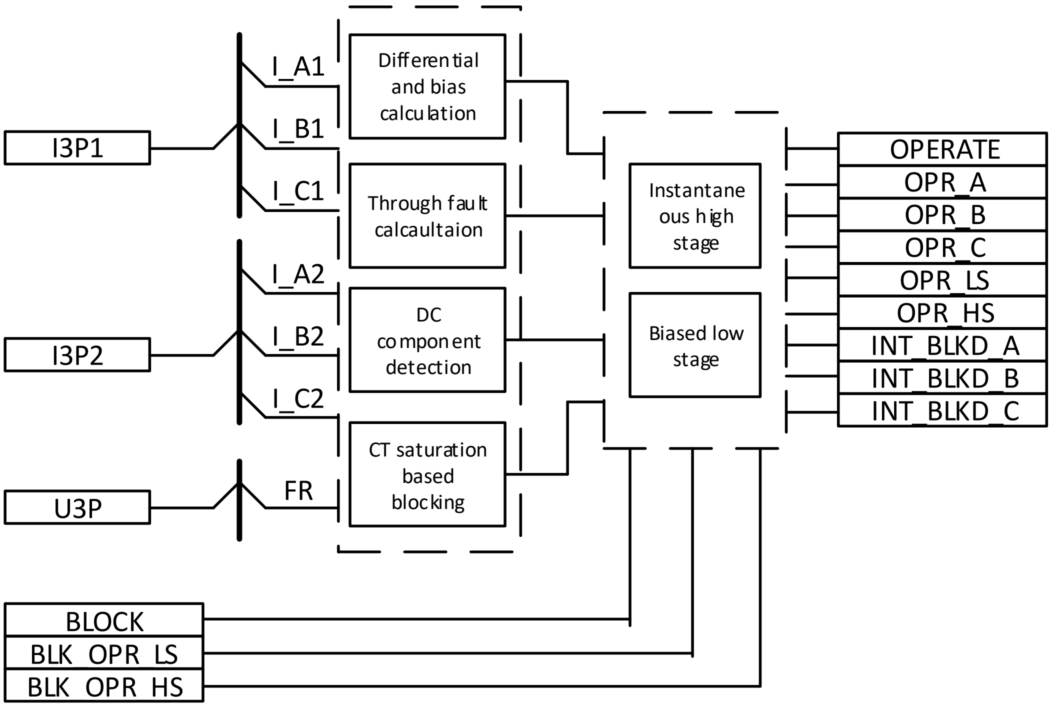


Figure 22 – Functional module diagram of MDPIF protection block [6]

There are two stages of differential protection function. The instantaneous stage is set up with the "High operate value" parameter, bias low stage is set up with "Low operate value", "End section 1", "End section 2", and "Slope section 2" parameters. [6]

Within the bias low stage, the protection should trip whenever the differential current exceeds the characteristic. Generally, the relay characteristic consists of three sections. In section one, tripping current is equals to set "Low operate value". In sections two and three, operating currents are determined by the following equations: [6]

$$I_{2\_operate} = I_{LOV} + (I_{bias} - I_{bES1}) \cdot \frac{k_{Slope\_section\_2}}{100} \qquad [6]$$

$I_{2\_operate}$... is the operating current at section 2

I_{LOV}... is the set “Low operate value”
I_{bias}... is the bias current determined by equation [2]
I_{bES1}... is the bias current determined by the set “End section 1” parameter
$k_{Slope\_section\_2}$... is the coefficient determined by the set “Slope section 2” parameter

$$I_{3\_operate} = I_{LOV} + (I_{bES2} - I_{bES1}) \cdot \frac{k_{Slope\_section\_2}}{100} + (I_{bias} - I_{bES2}) \qquad [7]$$

$I_{3\_operate}$... is the operating current at section 3
I_{LOV}... is the set “Low operate value”
I_{bES2}... is the bias current determined by the set “End section 2” parameter
I_{bES1}... is the bias current determined by the set “End section 1” parameter
$k_{Slope\_section\_2}$... is the coefficient determined by the set “Slope section 2” parameter
I_{bias}... is the bias current determined by equation [2]

During the external fault or normal operation conditions, the electrical angle between I_{A1} and I_{A2} is 180°, during the internal fault, the angle is 0°. The protection internal blocking signals will be inhibited if the angle between the line and generator currents is less than 50° or bias current drops below 30% of differential current.

Within the high instantaneous stage, the protection will operate either when the fundamental frequency component of the differential current exceeds the value determined by “High operate value” or when the instantaneous peak value of the differential current exceeds two and a half times of “High operate value”.

2.4.5 Earth-fault Protection Function Block

The generator earth-fault protection function in the REG 630 is subdivided into two separate functions: non-directional earth-fault protection function block EFxPTOC and directional earth-fault protection function block DEFxPDEF.

Non-directional earth-fault protection consists of three function blocks: low stage function block EFLPTOC, high stage function block EFHPTOC, and instantaneous stage function block EFIPTOC. The design of function blocks is shown in figure 23.

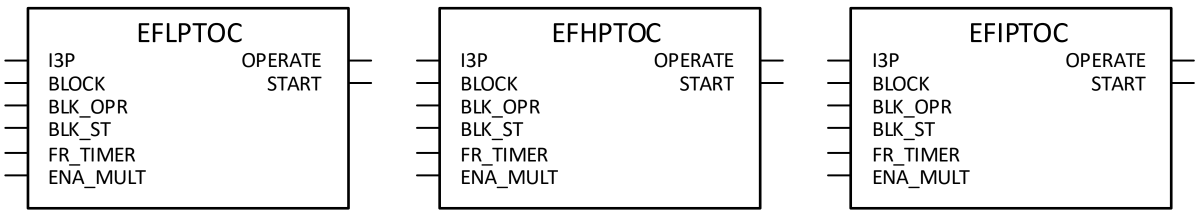


Figure 23 – The EFLPTOC, EFHPTOC, and EFIPTOC function blocks [6]

The module diagram shown in figure 24 demonstrates the operation of non-directional earth-fault protection.

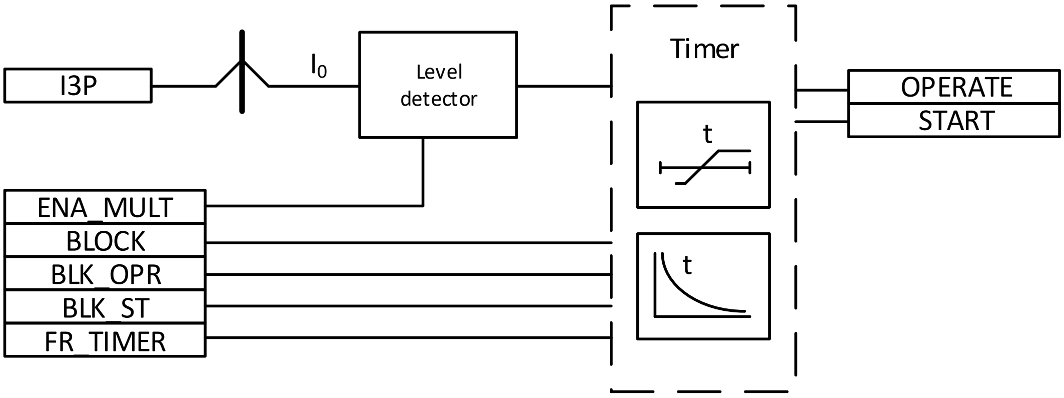


Figure 24 – Functional module diagram of EFLPTOC, EFHPTOC, and EFIPTOC protection blocks [6]

The residual current required for the operation trip might be measured directly or calculated from measured phase currents by the SMAI function.

The difference between EFLPTOC and EFHPTOC function block settings in the range of operating current is required for protection trip. Both functions support either DT or IDMT characteristics for protection operation and immediate, definite, or inverse time for protection reset. If there are special requirements for the operation curve, the advanced settings allow customization of the operation curve. The value of operation current is set up by the "Start value" parameter, the type of operating curve is chosen by the "Operating curve type" parameter. The time delay of protection operation is defined by the "Operate delay time" parameter.

EFIPTOC function block allows only immediate operation.

Directional earth-fault protection consists of two function blocks: low stage function block DEFLPDEF and high stage function block DEFHPDE. The design function blocks is shown in figure 25.

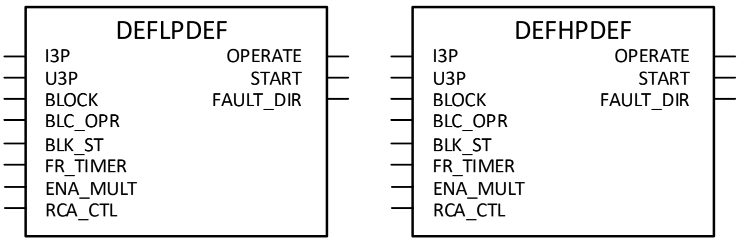


Figure 25 – The DEFLPDEF and DEFHPDEF function blocks [6]

The module diagram shown in figure 26 demonstrates the operation of directional earth-fault protection.

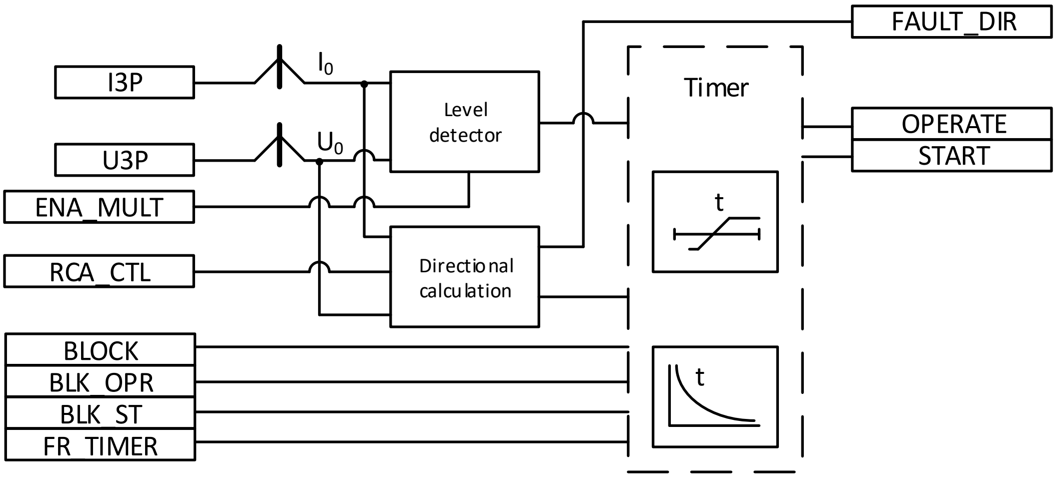


Figure 26 – Functional module diagram of DEFLPDEF and DEFHPDEF protection blocks [6]

The residual current required for the operation trip can be measured directly or calculated from measured phase currents by the SMAI function. The residual voltage is calculated from measured voltage phase values in the SMAI function block.

Direction earth-fault protection operates when polarizing (voltage) and operating (current) quantities exceed set limits and the angle between them lays in the operating zone. The operating quantities may be either negative sequence or zero-sequence voltage and current.

The difference between low and high stages functions DEFLPDEF and DEFHPDEF is limits for operating and polarizing quantities. Both functions support DT or IDMT operational curves.

The operation zone is defined by the function block settings “Characteristic angle”, “Directional mode”, “Operation mode”, “Max/min forward/reverse angle”, and “Directional mode”. The “Characteristic angle” parameter is defined by the grounding system of a generator. The “Directional mode” characteristic allows choosing of operating zone: either it is forward, reverse, or non-directional mode.

2.4.6 Loss of Excitation Protection Function Block

Three-phase underexcitation protection is implemented in the REG 630 by the UEXPDIS function block. The design of the function block is shown in figure 27.

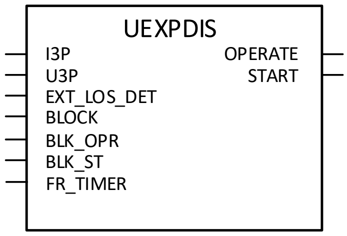


Figure 27 – The UEXPDIS function blocks [6]

The protection function is based on mho characteristic on the impedance plane. The function calculates the apparent impedance from the machine terminal current and voltages. If the impedance vector enters operational zone defined by function settings, protection trips. The operation time characteristic is given according to DT.

The module diagram shown in figure 28 describes the operation of the underexcitation protection function block.

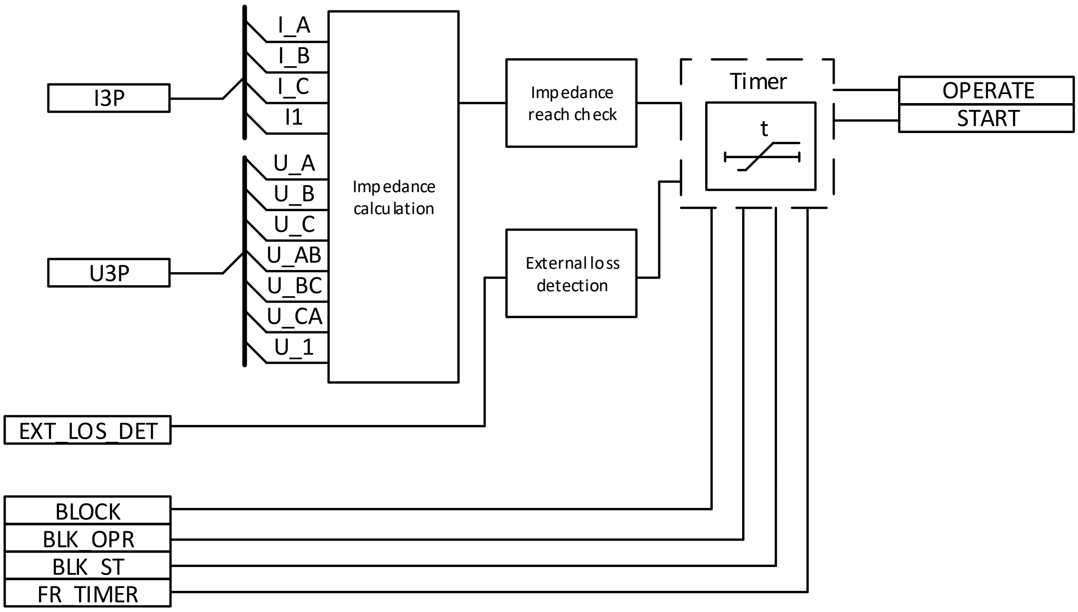


Figure 28 – Functional module diagram of UEXPDIS protection block [6]

The operation zone of the protection function is set up with “Offset”, “Diameter” and “Displacement” parameters.

Phase-earth, phase-to-phase, three-phase-earth, and three-phase voltages and currents might be used for impedance calculation. If all three-phase voltages and currents are available, the positive sequence three-phase calculation is preferable for the best accuracy.

3 Introduction to the Testing Equipment

3.1 The Testing Panel and REG 630 Control Panel

The REG 630 is built in the panel for testing purposes. The front side of the testing panel consists of three sections, each one corresponds to separate protection. The front side of the panel is shown in figure 29.

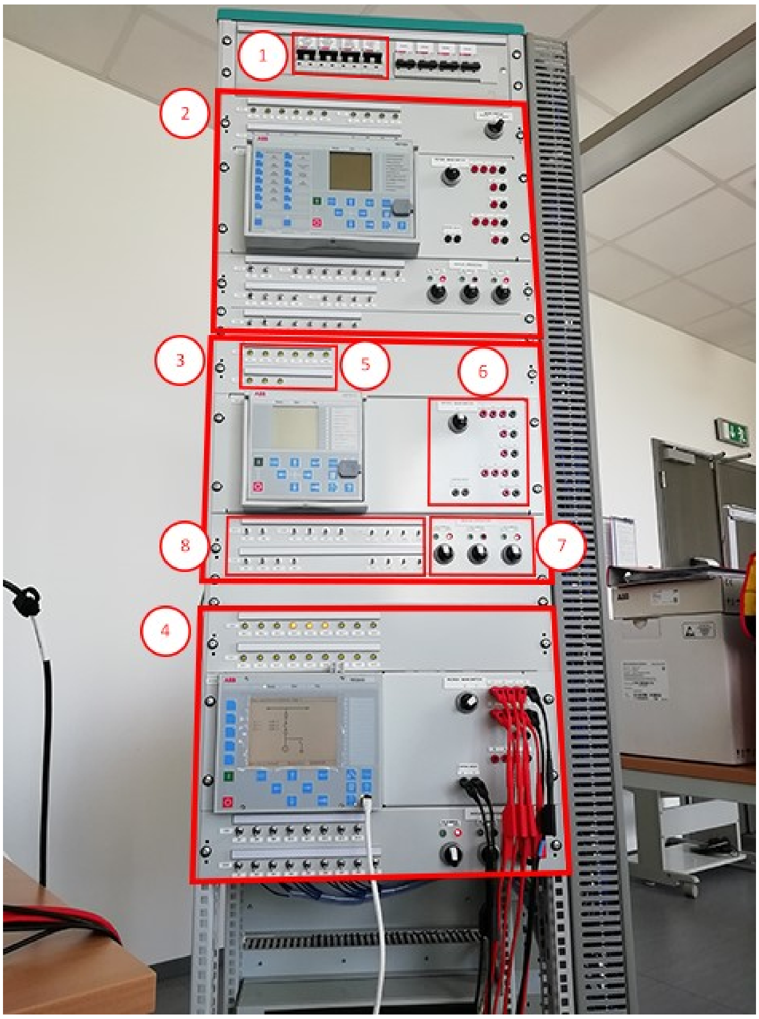


Figure 29 – The front view of the testing panel

The first block (1) is power supply switches. The second block (2) is the REF 620 control panel section. The third block (3) is the REF 615 control panel section. The fourth block (4) is the REG 630 control panel section. All three sections have the same structure: binary input block (8) and binary output block (5) sections, analog input block (6) and block for manual control of circuit breaker (CB), truck and earth switch (ES) (7).

The rear side of the panel consists of the logic side for CBs, truck, and ES behavior simulations. The rear side of the panel is shown in figure 30.

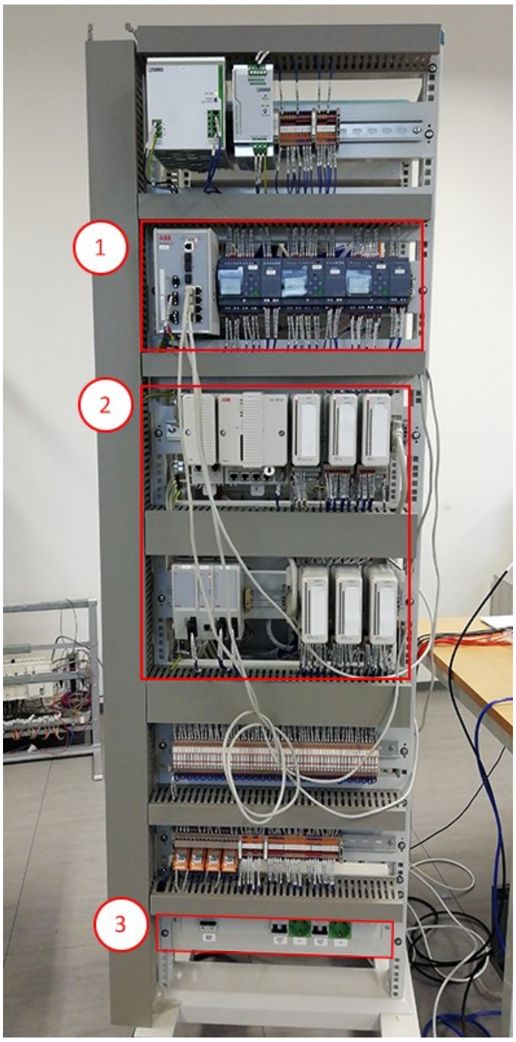


Figure 30 – The rear view of the testing panel

The first block (1) is a Siemens Logo device for the CB, ES, and truck logics and common switchboard AFS 660. The second block (2) is an ABB PLC block for simulation of CB, ES, and truck behavior. The third block (3) is the main power supply switch.

The REG 630 control panel only has been used during protection testing. The description of the REG 630 control panel is shown in figure 31.

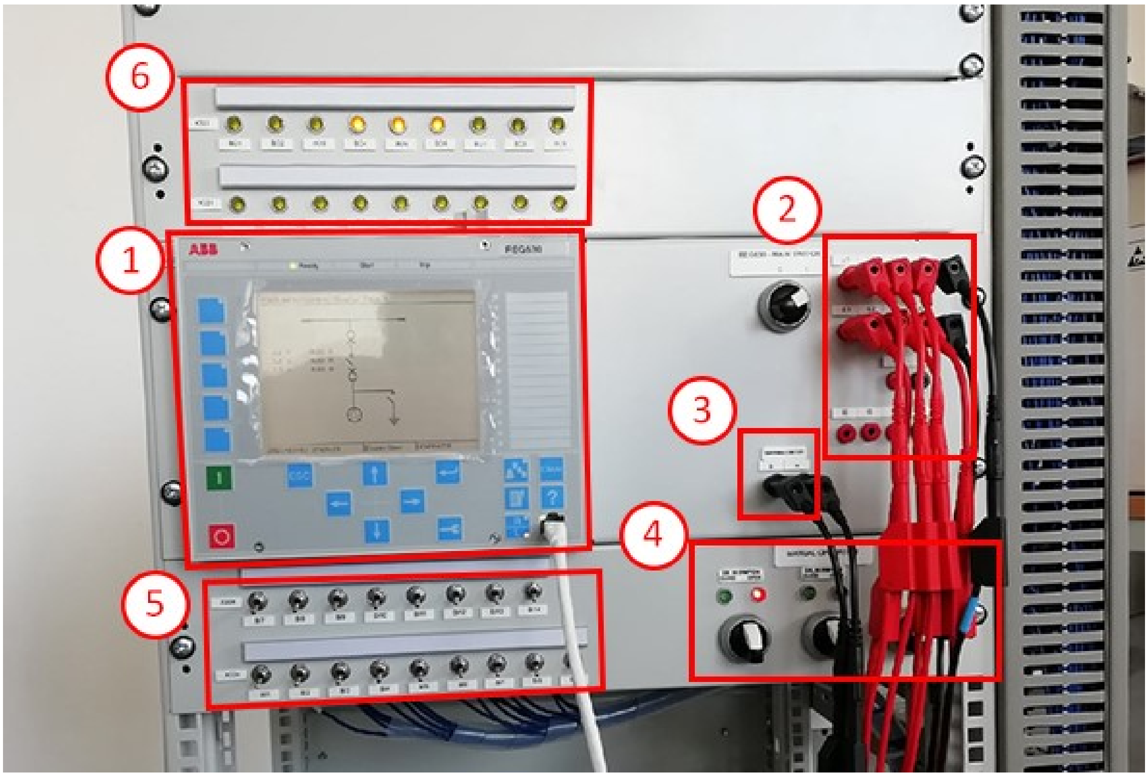


Figure 31 – The REG 630 control panel

The first block (1) is the REG 630 itself. On the front side the LHMI, front Ethernet port, and control buttons are presented. The LHMI is used to provide the figure of the protected part of the circuit, statuses of the equipment, setting of the protection blocks, and display of measurement results. The interaction with LHMI is done via control buttons. Front Ethernet port is used for communication between personal computer and the relay. The PCM600 configuration is uploaded to the IED via this port.

The second block (2) is used for the injection of secondary values of currents and voltages from the CT and VT. The analog input section consists of

- Three voltage inputs V1, V2, and V3, representing the secondary values of phase voltages from the terminal side of a generator.
- Six current inputs. Three of them IL1, IL2, and IL3 represent secondary currents from the terminal side of a generator, three current inputs I5, I6 and I7 represent secondary current from the neutral side of a generator.
- One residual current input representing the secondary value of the residual current.

Each of the above-listed sections has an N-neutral wire connection.

The third block (3) represents the tripping logic of a generator CB.

The fourth block (4) is manual control and statuses for a CB, truck, and ES. The logic of the CB, truck, and ES is simulated by the combination of the Siemens LOGO devices and ABB PLC (AC800, etc.).

The fifth block (5) is a binary input section. Each binary input is programmable according to the user requirements. During testing, the BI14 was used to clear the IED status after faults and protection operation.

The sixth block (6) is a binary output section. All LEDs are programmable according to user requirements. During testing, the BO1 was used to indicate if any protection operates.

Since there is no real MV generator was used during the protection testing, the generator and connected apparatus (circuit breaker, truck, and earth switch) were simulated by different equipment. The Siemens LOGO and ABB PLCs simulated the apparatus. The tester OMICRON CMC 310 simulated the secondary values of the generator currents and voltages.

3.2 The Tester OMICRON CMC 310

OMICRON CMC 310 is a special device designed for three-phase testing of protection and measurement equipment. The front view of the device is shown in figure 32. The parts of OMICRON used in testing are described further.

Figure 32 – The tester OMICRON CMC 310 front view

The first block (1) is the power supply switch. The second block (2) is the voltage input sector. There are two modes for voltage supply: 3x300VAC or 1x600VAC. The third block (3) is the current output sector. There are two modes of current supply: 3x32A or 3x430VA. The fourth block (4) is the binary input sector. Binary input 1 is used for tripping logic connection, which allows measuring the tripping time of the circuit breaker. The fifth block (5) is the CMC control panel and screen. All manipulations with the tester are done by this panel. The sixth block (6) is the I/O button. By pushing this button set currents and voltages are injected into the testing panel. The seventh block (7) is a control wheel, which can be used for control of the injecting currents and voltages.

The simulation settings are adjustable via OMICRON CMC 310 parameters allowed in the "Hardware settings". These settings are also used to establish the tripping logic of a circuit breaker.

The "Direct" window allows to set up the injecting currents and voltages and their angles. The examples of using this window for particular protection testing are described in chapter 6.

3.3 The General Parameters Chosen for Protection Testing

As it was mentioned before, no real generator and equipment were used for training purposes. Hence, there is no real CT, VT, and other apparatus. The OMICRON tester simulated the secondary values of the MV generator CT and VT. The Siemens LOGO and ABB PLCs simulated the tripping logic of the circuit breaker.

The relation between secondary and primary values was chosen for the best understanding of protection operation principles. The simplicity of further calculation and avoidance of unnecessary difficulties were the main targets during choosing the rated parameters for the simulation. Table 4 presents the rated secondary and primary values chosen for protection testing. The methods of setting the rated parameters are considered in the next chapter.

The fault conditions are also simulated by changing the secondary values of currents and voltages. The logic of performing with the secondary values injected by the OMICRON is dependable on the type of protection in the test and described in chapter 5.

Table 4 – The rated parameters of a generator circuit chosen for protection testing

The name of the parameter	Secondary value (OMICRON injection)	Primary values (calculated by IED)	Description
phase-to-phase voltages V1, V2, V3	100 V	12 kV	The value corresponds to the MV range
Phase current of a generator I1, I2, I3	1 A	100 A	The set value allows avoiding difficult calculation of percentage and p.u. values
Residual current I0	1A	100 A	The set value allows avoiding difficult calculation of percentage and p.u. values
Residual Voltage V0	100 V	6.928 kV	The value is equal to phase-to-ground voltage

4 Programming in PCM600

PCM600 is a programming tool designed for interaction with ABB IEDs. PCM600 allows interaction with all Relion product lines. Main functionalities of PCM600 are the following follows:

- The setting of the parameter for the particular IED. Supervision, measurement, control, protection, binary and analog IO programming, and other functions are available for the particular IED via PCM600.
- Establishment of the communication between several ABB IEDs. The related standard fully covers the communication protocol. [12]
- The control and supervision over substation IEDs.

For training purposes, the PCM600 was used to set up the configuration and protection parameters for the REG 630. The programming in PCM600 is fully described in further subparagraphs.

4.1 Plant Structure Overview

Every project in PCM600 has a definite structure. The project itself contains Substation level. A substation may be subdivided into several Voltage levels. Voltage level may contain several Bays, and Bay has one or several IEDs. The project structure, which was built for training is shown in figure 33.

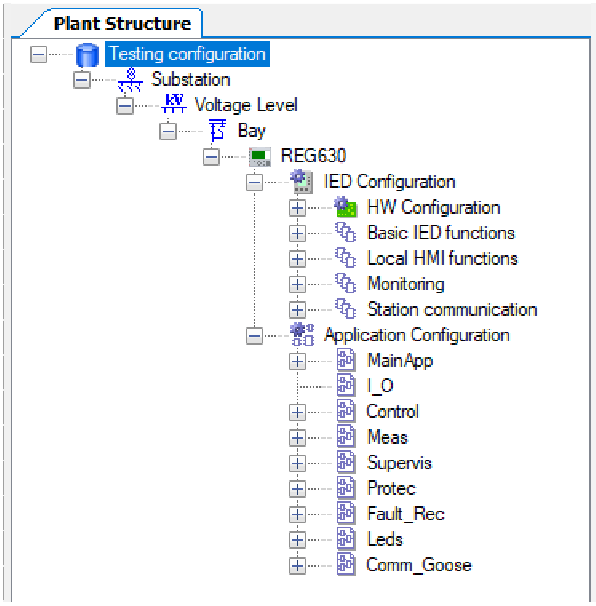


Figure 33 – Project structure in PCM600

The REG 630 configuration is done via two parameter sections: IED configuration and Application configuration.

4.2 IED Configuration

IED configuration is used to set the hardware settings, like the ratio between secondary and primary currents and voltages of the generator. The full list of configured parameters with the description is given below. The configuration of the parameters is done via the Parameter Setting window.

1. Hardware (HW) configuration. This configuration allows configuring the hardware binary and analog modules of the REG 630.
2. Basic IED functions. This configuration allows setting the group of settings that will be used in the further calculation of protection and other functionalities of the REG 630. This configuration group also configures analog input settings.
3. LHMI functions. This configuration allows setting of function keys settings, HMI parameters, and programmable LEDs parameters.
4. Monitoring. This configuration allows setting of the parameters of the recording function block DRRDRE.
5. Station configuration. This configuration allows setting of the parameters of communication between the REG 630 and other IEDs, such as IP address, Gateway, LAN port address, etc.

The IED configuration structure is shown in figure 34.

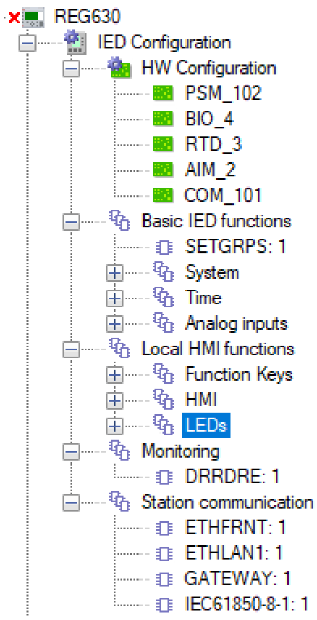


Figure 34 – The IED configuration structure in PCM600

The main settings for testing purposes are HW Configuration and Basic IED functions. Other settings have their default parameters.

Note: Settings group 1 is chosen for protection testing and training purposes. Settings of this group are discussed in further chapters.

Note: The red cross near the REG 630 icon means that there is no live connection between the PC and the REG 630. However, it does not affect the configuration settings.

4.2.1 HW Configuration

HW configuration allows direct setting of hardware modules of the REG 630. Generally, there are four hardware modules built in the REG 630. Only AIM_2 module settings are changed under testing requirements, other modules have default parameters.

AIM_2 module is responsible for analog input values settings. The fragment of module setting for current and voltage analog inputs is shown in figure 35.

REG630 - Application Configuration | **REG630 - Parameter Setting**

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
AIM_2					
NAMECH1		CH1			13 characters
InputType1		Current			
ReversePolarity1		No			
CTsec1		1,0	A	0,1	10,0
CTprim1		100	A	1	99999
NAMECH8		CH8			13 characters
InputType8		Voltage			
VTsec8		100,000	V	0,001	999,999
VTprim8		12,000	kV	0,001	9999,999

Figure 35 – The AIM_2 analog module settings in PCM600

4.2.2 Basic IED Functions

Basic IED function settings allow changing the primary and residual voltage and current values for each setting group. The settings of base phase and residual values are shown in figure 36.

REG630 - Application Configuration | **REG630 - Parameter Setting**

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
BASEPH: 1					
Voltage base Val PP		12,00	kV	0,01	440,00
Current base Val Ph		100	A	1	9999
S base value 3Ph		13856,00	kVA	0,05	1800000,00

REG630 - Application Configuration | **REG630 - Parameter Setting**

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
BASERES: 1					
Voltage base Val Res		6,928	kV	0,001	440,000
Current base Val Res		100	A	1	6000
S base value Res		808,29	kVA	0,05	18000,00

Figure 36 – The group phase and residual current and voltage settings for analog inputs of the REG 630

4.3 Application Configuration

When the project structure is prepared and all required IEDs are added, the Application configuration must be done. Application configuration is a logical structure of IED settings. This type of configuration describes signaling of the IED and covers next points:

1. Analog and binary signals description and purpose (IO description list).
2. Measurements configuration (A measurement description list).
3. Supervision of the REG 630 configuration (A supervision description list).

4. Protection configured in the REG 630 (Protection description list).
5. Recording functionality (Fault_Recording description list).
6. LED configuration (a LEDs description list).
7. GOOSE communication.

The application configuration is shown in figure 40.

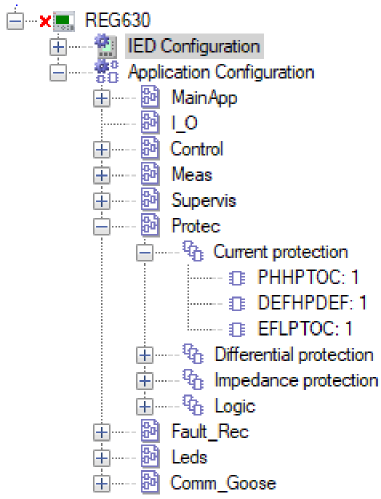


Figure 37 – The application configuration in PCM600

The most important configuration parts are IO, measurement, and protection. They are described in further subparagraphs. Other settings either have default parameters or are set as default with the respective manual. [6] [10] [13] [14]

The application configuration is done via predefined functional blocks allowed for the REG 630. The block set available for configuration is predefined by the connectivity package available in PCM600.

4.3.1 Input and Output Configuration

The IO configuration describes the input and output signals to the REG 630 hardware modules. The signals are dependent on the hardware configuration of the IED and tripping logic of CB, truck, and ES. The IO signals configuration for protection testing and training purposes is shown in figure 38.

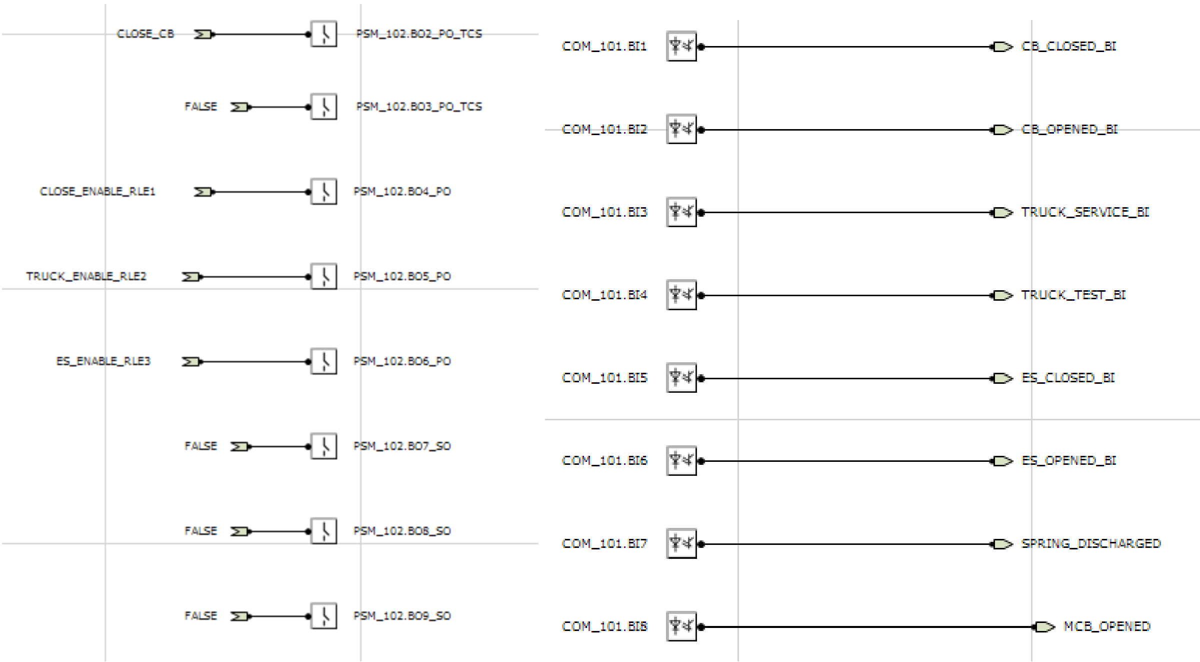


Figure 38 – The IO application configuration of the REG 630 in PCM600

<u>Note:</u> This configuration is only applicable to the testing panel described in chapter 3.1. The IO configuration is done according to panel layout drawings and logic signals wiring is available only for this particular testing panel.

4.3.2 Measurement configuration

The measurement configuration describes two types of connection: the analog current and voltage inputs calculation module and the measurement block configuration. The configuration of analog current and voltage inputs is done according to the layout drawings of the testing panel. The configuration of measurement blocks is done with the manual. [6]

The measurement blocks provide measurement results of analog inputs and available in the LHMI in the corresponding directory. The measurement configuration is shown in figures 39 and 40.

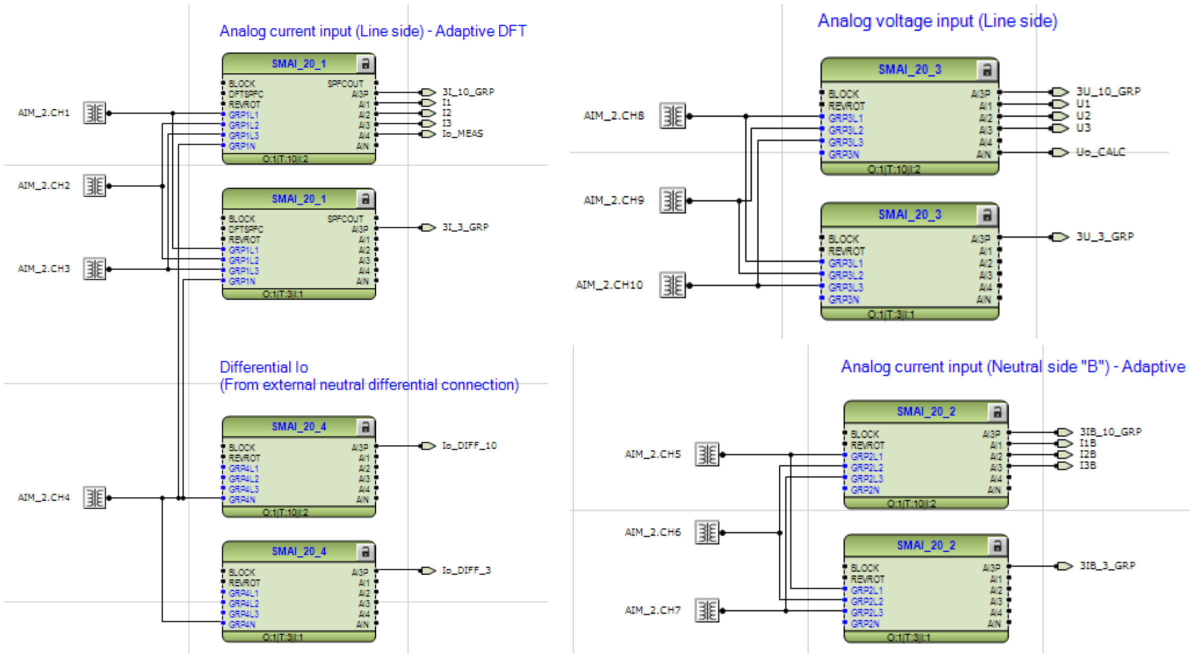


Figure 39 – The analog current and voltage input of the testing panel configuration in PCM600

Figure 40 – Configuration of measurement function blocks in PCM600

4.3.3 Protection configuration

The protection configuration allows setting up all protection functionalities required in a particular application of the REG 630. As the scope of this diploma thesis is differential protection, earth-fault protection, and loss of excitation protection functionalities testing, the next protection function blocks were used:

1. PHHPTOC basic overcurrent protection function block. This protection block is required for safe operation with the REG 630 and allows to avoid the damage of equipment during tests.
2. MPDIF differential protection function block.
3. EFHPTOC non-directional earth-fault protection function block.
4. DEFHPDEF directional earth-fault protection function block.
5. UEXPDIS loss of excitation protection function block.

The application configuration for each block is shown in figure 41.

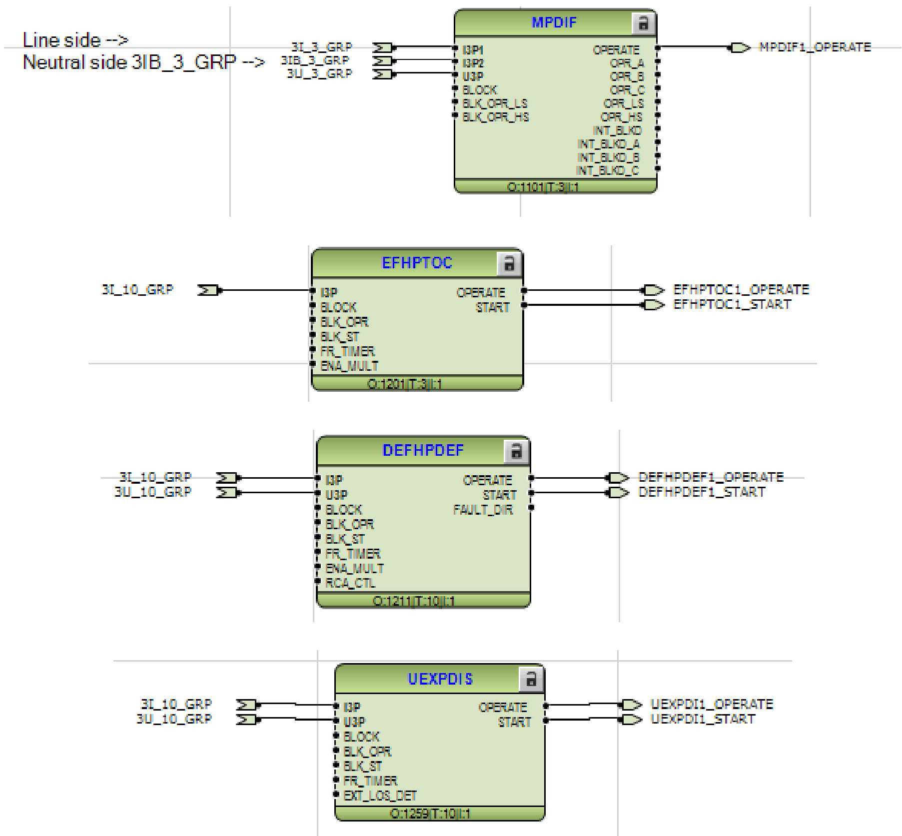


Figure 41 – The application configuration for each tested protection function block

The Parameter Setting window allows to set up the protection parameters for testing. Detailed configuration of the protection parameters is described for each protection in chapter 5.

4.4 Graphical Display Editor

Graphical display editor allows to set up the graphical image which will be shown at the LHMI. The graphical display which is shown in the LHMI is presented in Figure 42.

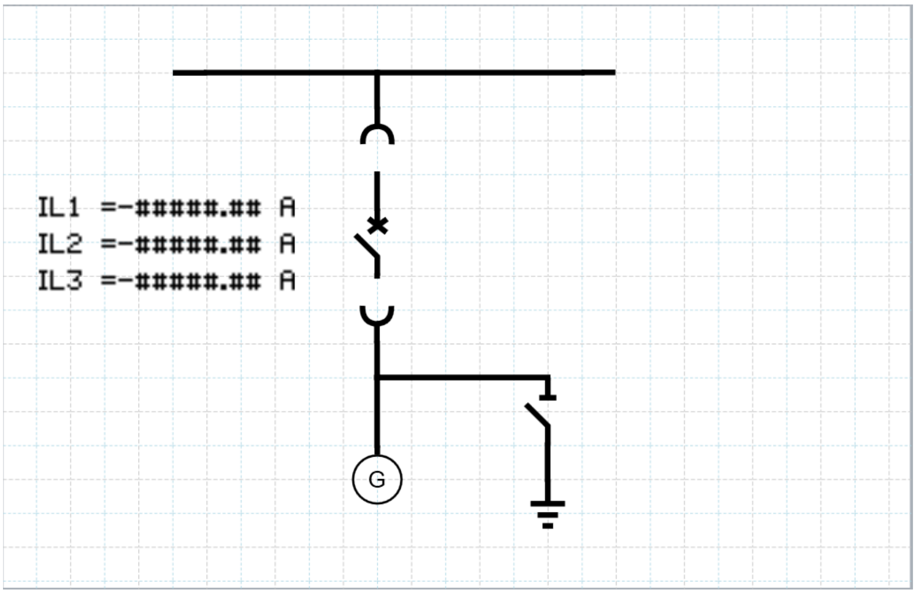


Figure 42 – The graphical display is visible in the LHMI

The status of CB, truck, and ES is provided from the corresponding control functional block from the application configuration.

5 Preparation of Training Materials

This chapter is dedicated to the collection of all the materials required for a training organization. The following subparagraphs have sufficient information for safe and useful operation with the REG 630. Furthermore, the function block parameters described in chapter 2.4 are fully explained in the following subparagraphs.

Each subgraph is related to particular MV generator protection. Provided information covers the following aims:

1. The wiring diagram for protection testing.
2. The protection settings for correct operation.
3. The visualization of the protected zone for the best understanding of the protection setting.

The common steps for each protection are:

1. Inject the set currents and voltages via the tester.
2. If the protection does not operate:
    a. Write down the necessary data to the corresponding table.
    b. Stop the injection before changing the injecting values.
    c. Enter the next measurement values.
3. If protection operates:
    a. Write down the necessary data to the corresponding table.
    b. Stop the injection before changing the injecting values.
    c. Clear the protection status via BI14 or by the LHMI of the REG 630.
    d. Enter the next measurement values.

The clarification of the above-mentioned steps for each protection testing is provided in further chapters.

The common point for each protection testing is that the secondary values of an MV generator CTs and VTs are simulated with the OMICRON CMC 310. The REG 630 is connected to virtual CB simulated by the control system of the testing panel. The CB signal contact, i.e. opening coil, is connected to the tester, which allows measuring of tripping time at the OMICRON CMC 310. The primary values are recalculated by the IED by the set ratio, which is described in chapter 4.

5.1 Training Materials for Differential Protection Testing

5.1.1 Single Line and Wiring Diagrams for Differential Protection Testing

The theoretical principles of differential protection were fully described in chapter 1.1.

The single line diagram of differential protection application is given in figure 43. This diagram shows the simple way of differential protection application for an MV generator.

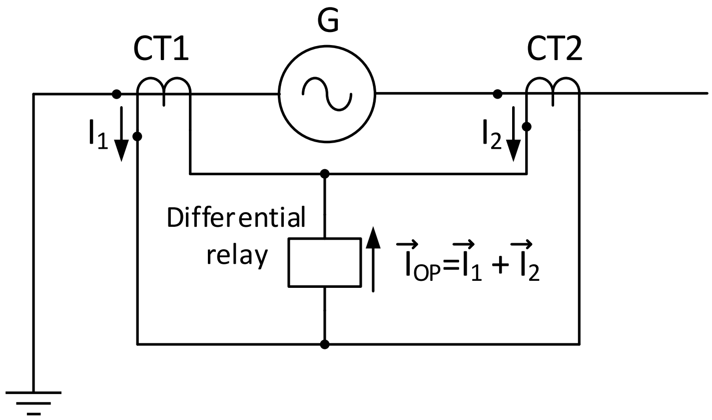


Figure 43 – The single line diagram of generator differential protection application

The wiring diagram shown in figure 44 describes the connection of OMICRON CMC 310 and the testing panel with the REG 630 for differential protection testing.

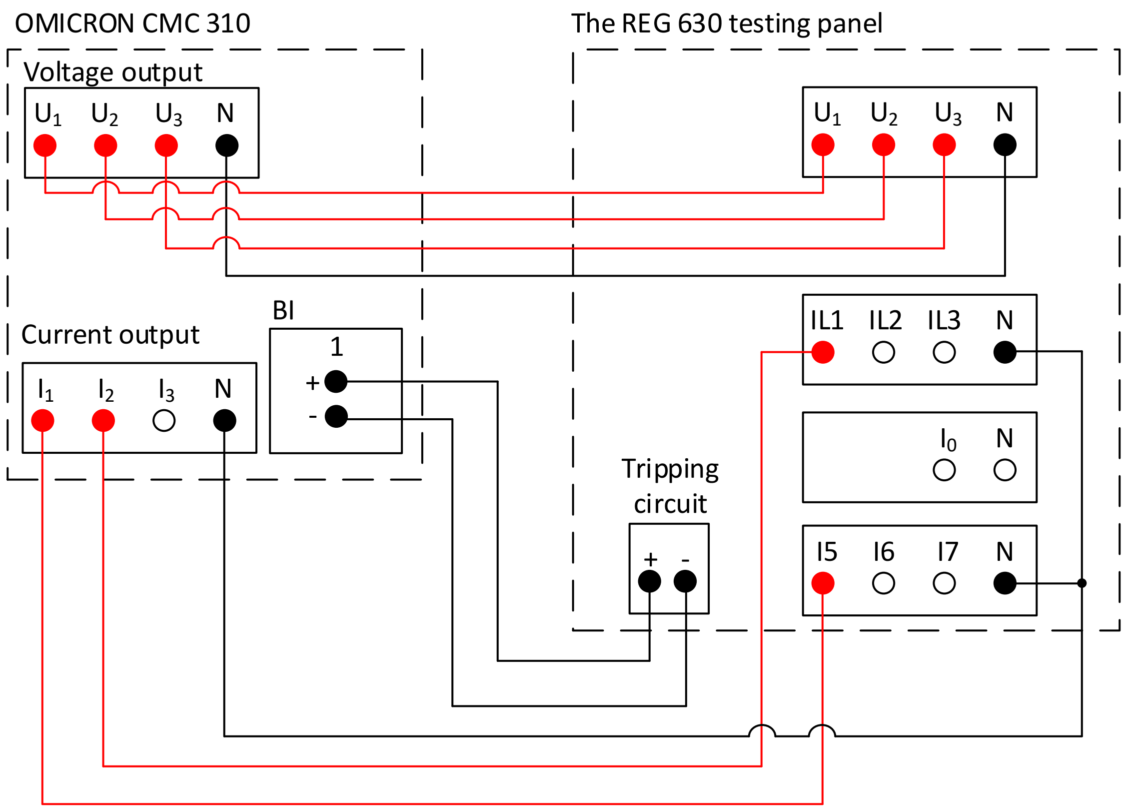


Figure 44 – The wiring diagram for differential protection testing

Table 5 presents currents, voltages, and binary signals transcription.

Table 5 – The description of the tester and panel analog and binary IOs

Current / voltage / binary signal name at the tester output	Current / voltage / binary signal name at the testing panel	Description
U1, U2, U3	U1, U2, U3	Secondary voltages from the terminal side of a generator
I1	I5	Phase A current at the neutral side of a generator
I2	IL1	Phase A current from the terminal side of a generator
+ / -	+ / -	Binary signals for MCB operation recording. Allows to record a time of protection operation at the tester

5.1.2 Differential Protection Setting

The tester OMICRON CMC 310 has only three current outputs. It means that it is impossible to test three-phase differential protection. However, the one-phase differential protection testing approach has the following positive sides:

1. Visual representation of the angle between currents and ease manipulation of currents' module and direction.
2. A simplified approach gives a full understanding of the protection operation principle.
3. The MPDIF function protection block of the REG 630 allows one-phase differential protection operation without any influence on the testing result.

The protection setting is done in the PCM600 or via LHMI. Protection settings for testing are shown in figure 45.

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
MPDIF: 1					
Operation		On			
CT connection type		Type 1			
Setting Group1					
High operate value		300	%	100	1000
Low operate value		20	%	5	30
Slope section 2		25,0	%	10,0	50,0
End section 1		40	%	0	100
End section 2		120	%	100	300

Figure 45 – PCM600 configuration for the MPDIF function block

The protection zone determined by settings is shown in figure 46.

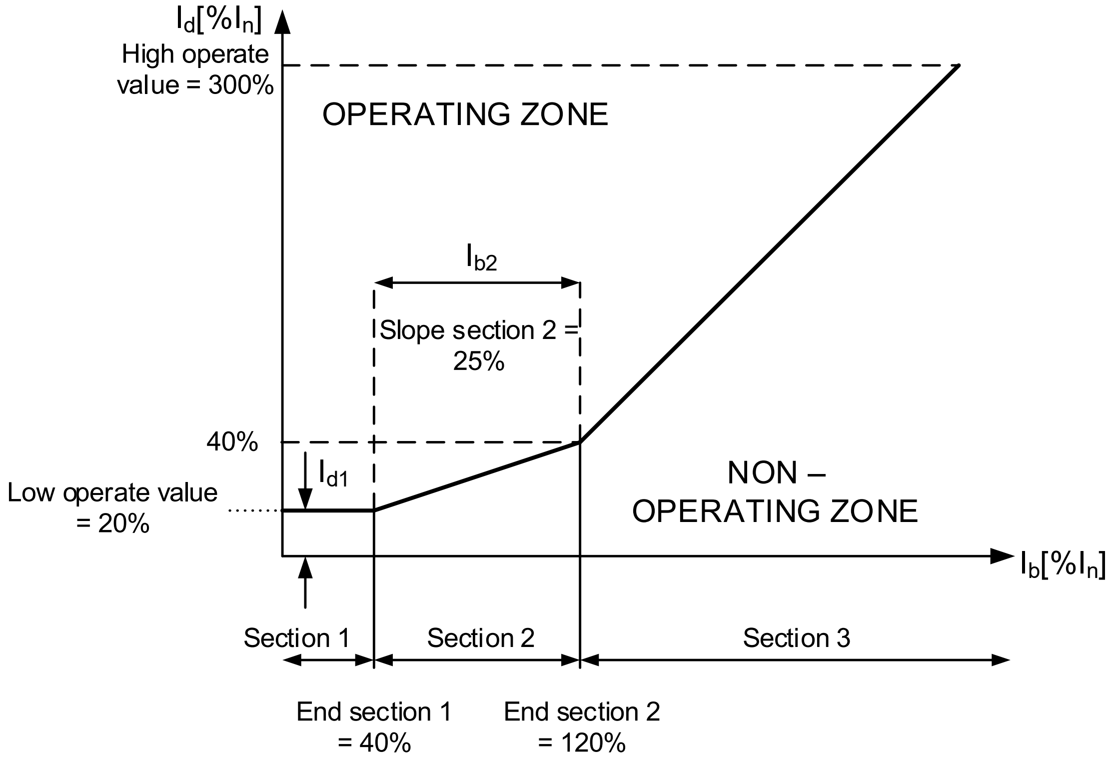


Figure 46 – The differential protection operating zone determined by the MPDIF function block setting

5.1.3 Assignment and Clarification for Differential Protection Testing

The scope of differential protection testing is to check all three sections of the operating characteristic of the relay. Five or six locations are chosen either for non-operating or operation zone. Protection trips whenever the differential (operating) current I_d exceeds the set limit.

The rated current is equal to 100A, thus the percentage values will be equal to ampere representation.

OMICRON CMC 310 simulates secondary values of CTs and VTs, but REG 630 calculates primary values by the set ratio. Furthermore, the “Monitoring” and “Measuring” windows at the LHMI of the REG 630 show absolute values of differential and bias currents. If the set rated current is not equal to 100A, the percentage value will not be equal to the absolute value.

At the first section of operating characteristic, I_d = 20%, or 20A in this case;

In the second section, the operating percentage value for the determined bias current I_{bias} is calculated with equation [6]. In this case, the absolute value is equal to the percentage value;

In the third section, the operation value for the determined bias current I_{bias} is calculated with equation [7]. In this case, the absolute value is equal to the percentage value.

The values of actual differential current and bias current based on injected currents are calculated by equations [1] and [2] respectively. The multiplication by 100% is required to convert p.u. values into a percentage value.

The steps for differential protection testing are described below:

1. Make the circuit according to the wiring diagram in Figure 44 for differential protection testing.
2. Set the MPDIF function block parameters as described in Figure 45.
3. For each measurement point:
    a. Select the I_1 and I_2 injecting secondary currents and their electrical angles and calculate relevant differential and bias currents using the equations [1] and [2].
    b. Compare calculated bias current with defined operation characteristic section and compare calculated differential current with set operation current related to the section. Make an assumption whether protection will trip or not.
    c. Inject the chosen I_1 and I_2 currents via the tester. Write down all the required parameters to the corresponding table.
4. Conclude, whether the set REG 630 operation characteristic corresponds to measured values.

An example of training completion is presented in chapter 6.1.

5.2 Training Materials for Earth-Fault Protection Testing

As earth-fault protection in the REG 630 is subdivided into directional and non-directional function blocks, their settings will be overlooked separately in further chapters.

5.2.1 Single Line and Wiring Diagrams for Non-Directional Earth-Fault Protection Testing

The theoretical principles of the non-directional earth-fault protection were fully described in chapter 1.2.

The single line diagram of the non-directional earth-fault protection application is shown in figure 47. This diagram shows the simple application of non-directional protection against earth faults in an MV generator.

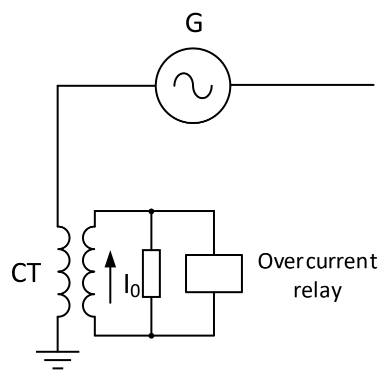


Figure 47 - The single line diagram of generator application of non-directional earth-fault protection

The wiring diagram shown in figure 48 describes the connection of OMICRON CMC 310 and the testing panel with the REG 630 for earth-fault protection testing.

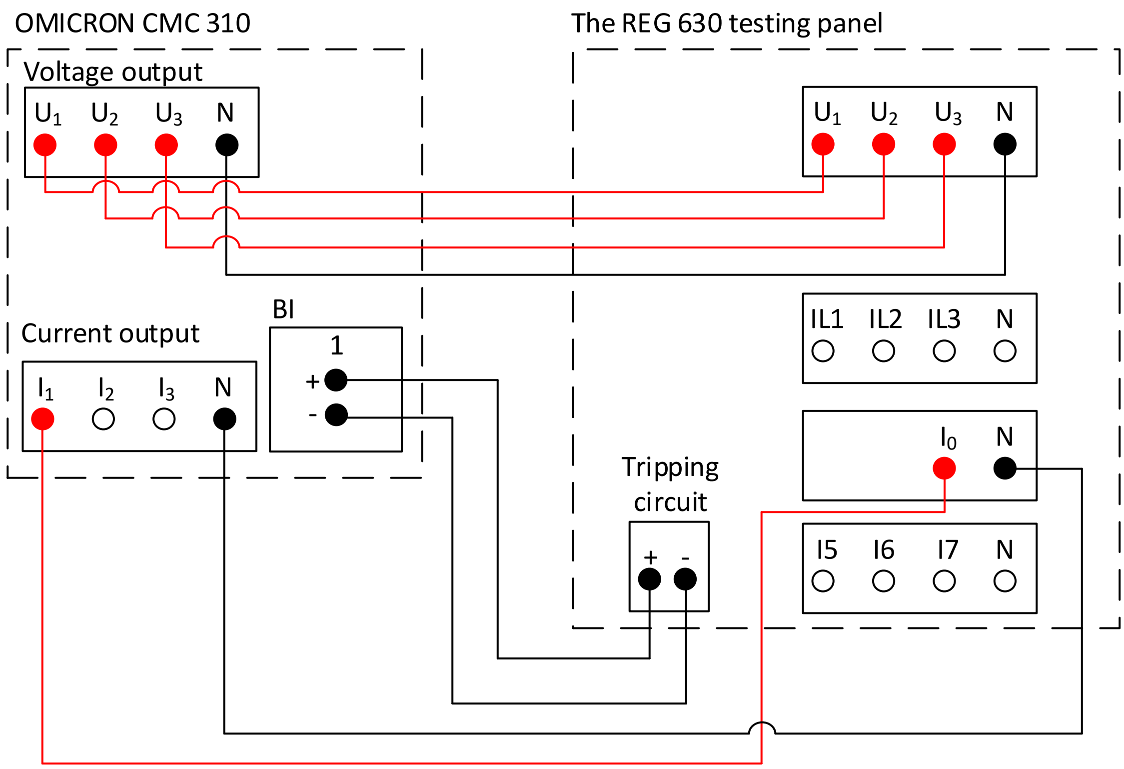


Figure 48 – The wiring diagram for non-directional earth-fault protection testing

Table 6 presents currents, voltages, and binary signals transcription.

Table 6 - The description of the tester and panel analog and binary IOs

Current / voltage / binary signal name at the tester output	Current / voltage / binary signal name at the testing panel	Description
U1, U2, U3	U1, U2, U3	Secondary voltages from the terminal side of a generator
I1	I0	Residual current, secondary value
+ / -	+ / -	Binary signals for MCB operation recording. Allows to record a time of protection operation at the tester

5.2.2 Non-Directional Earth-Fault Protection Setting

As it was mentioned in chapter 2.4, non-directional protection has three function blocks. The difference between low and high stage function blocks is only in the range of operation current. Further settings are applied for the EFHPTOC function block for high stage non-directional protection, but those settings might be also applied for the EFLPTOC function block.

Two types of operating time curves are available for non-directional earth-fault protection. Both DT and IEC normal inverse time characteristics will be tested.

The protection setting is done in the PCM600 or via LHMI. Protection settings for DT characteristic testing are shown in figure 49.

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
EFHPTOC: 1					
Operation		On			
Setting Group1					
Start value		0,30	pu	0,10	40,00
Start value Mult		1,0		0,8	10,0
Time multiplier		1,00		0,05	15,00
Operating curve type		IEC Def. Time			
Operate delay time		**2,00**	s	0,02	200,00

Figure 49 - PCM600 configuration for the EFHPTOC function block, IEC DT operating curve

The protection zone determined by the settings is shown in figure 50.

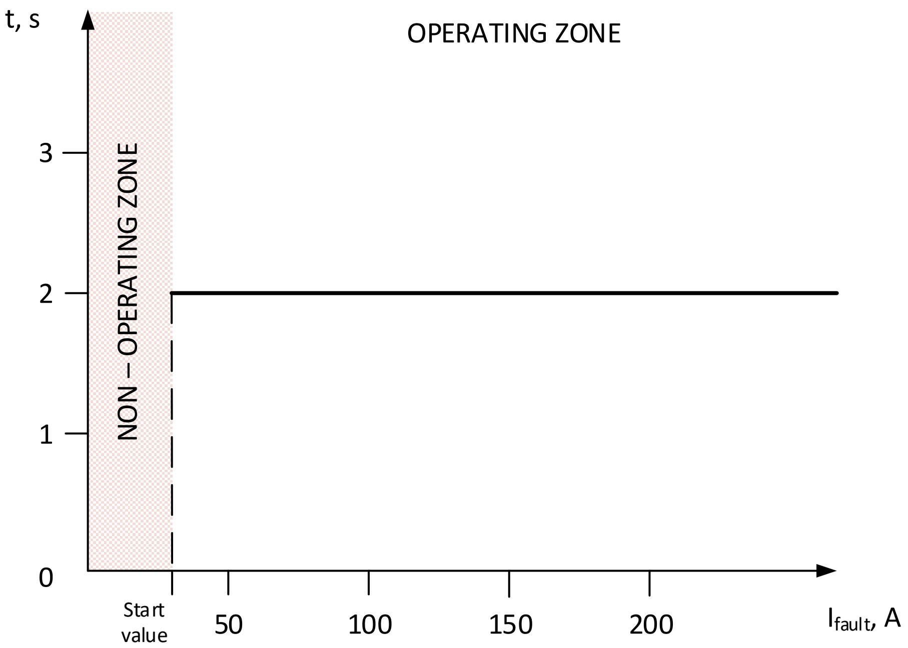


Figure 50 – The non-direction earth-fault protection operating zone determined by the EFHPTOC function block setting, IEC DT operation curve

The “Start value” parameter limits a non-operating zone of the protection. The “Operate delay time” parameter forms an operating characteristic as a horizontal line.

Protection settings for IDMT characteristic testing are shown in figure 51.

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
EFHPTOC: 1					
Operation		On			
Setting Group1					
Start value		1,00	pu	0,10	40,00
Start value Mult		1,0		0,8	10,0
Time multiplier		1,00		0,05	15,00
Operating curve type		IEC Norm. inv.			
Operate delay time		2,00	s	0,02	200,00

Figure 51 - PCM600 configuration for the EFHPTOC function block, IEC normal inverse operating curve

The protection zone determined by the settings is shown in figure 52.

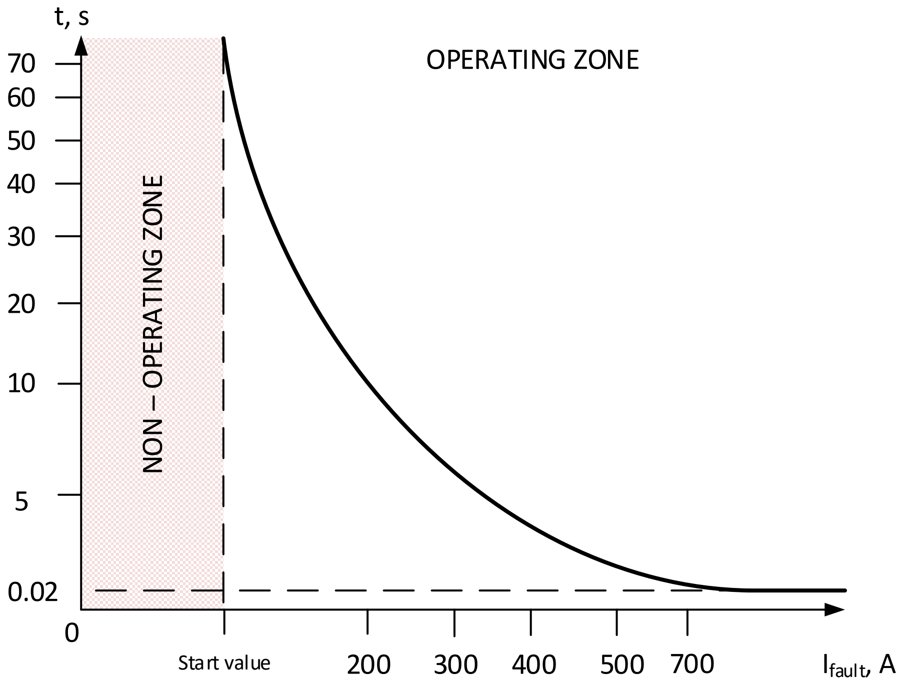


Figure 52 - The non-direction earth-fault protection operating zone determined by the EFHPTOC function block setting, IEC normal inverse operation curve

The “Start value” parameter limits a non-operating zone of the protection. The “Operating curve type” parameter forms an operating characteristic as an IEC normal inverse curve. Value of 0.02 seconds represents minimal operating time.

5.2.3 Assignment and Clarification for Non-Directional Earth-Fault Protection Testing

The scope of non-directional earth-fault protection testing is to check the operating times of the protection, determined by the operating curve characteristics available in the EFHPTOC function block. For DT characteristics, two points were chosen either for operating and non-operation zones. For the IEC normal inverse characteristic, five points were chosen either for operating and non-operating zones. Protection trips whenever the value of the residual current I_0 exceeds the set limit, with the time defined by the chosen characteristic.

The rated current is equal to 100A, thus the p.u. values multiplied by 100 will be equal to ampere representation.

OMICRON CMC 310 simulates secondary values of CTs and VTs, but REG 630 calculates primary values by the set ratio. Furthermore, the "Monitoring" and "Measuring" windows at the LHMI of the REG 630 show primary values of the residual current. If the set rated current is not equal to 100A, the measured value will not be equal to p.u. value multiplied by 100.

For the DT characteristic, the start value is $0.3 \cdot I_n$, i.e. 30A of absolute value. The definite operating time is 2 seconds.

For the IEC normal inverse characteristic, the start value is $1.0 \cdot I_n$, i.e. 100A of absolute value. The operating time for any IDMT characteristic can be calculated by the following equation: [6]

$$t = \left(\frac{A}{\left(\frac{I_{meas}}{I_{set\_lim}}\right)^{C} - 1} + B \right) \cdot k \qquad [8]$$

A, B, C... are curve parameters
I_{meas}... is measured current
I_{set_lim}... is the set limit for I_0
k... is set "Time multiplier" parameter

Table 7 shows values for IEC normal inverse characteristic parameters. A full table for all IDMT curves available for EFxPTOC function blocks is available in the corresponding manual. [6]

Table 7 – Curve parameters for IEC normal inverse characteristic

Curve name	A	B	C
IEC normal inverse	0.14	0.0	0.02

The steps for non-directional earth-fault protection testing are described below:

1. Make the circuit according to the wiring diagram shown in Figure 48 for non-directional earth-fault protection testing.
2. Set the EFHPTOC function block parameters as described in Figure 49 for DT operating curve and in Figure 51 for IDMT operating curve.
3. For each measurement point:
    a. Select the injecting secondary residual current value I_0 and its angle and calculate expecting operating time using the equation [8].
    b. Inject the set residual current, write down all required measured parameters to the corresponding table.
4. Check if the measured characteristic matches with the selected one.

An example of training completion is presented in chapter 6.2.

5.2.4 Single Line and Wiring Diagrams for Directional Earth-Fault Protection Testing

The theoretical principles of the directional earth-fault protection were fully described in chapters 1.2 and 2.4.

The single line diagram of the directional earth-fault protection application is shown in figure 53. This diagram shows the simple application of directional protection against earth faults in an MV generator.

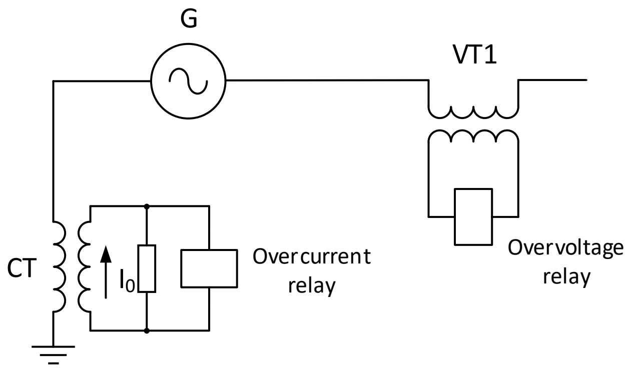


Figure 53 – The single line diagram of generator application of directional earth-fault protection

The wiring diagram shown in figure 54 describes the connection of OMICRON CMC 310 and the testing panel with the REG 630 for earth-fault protection testing.

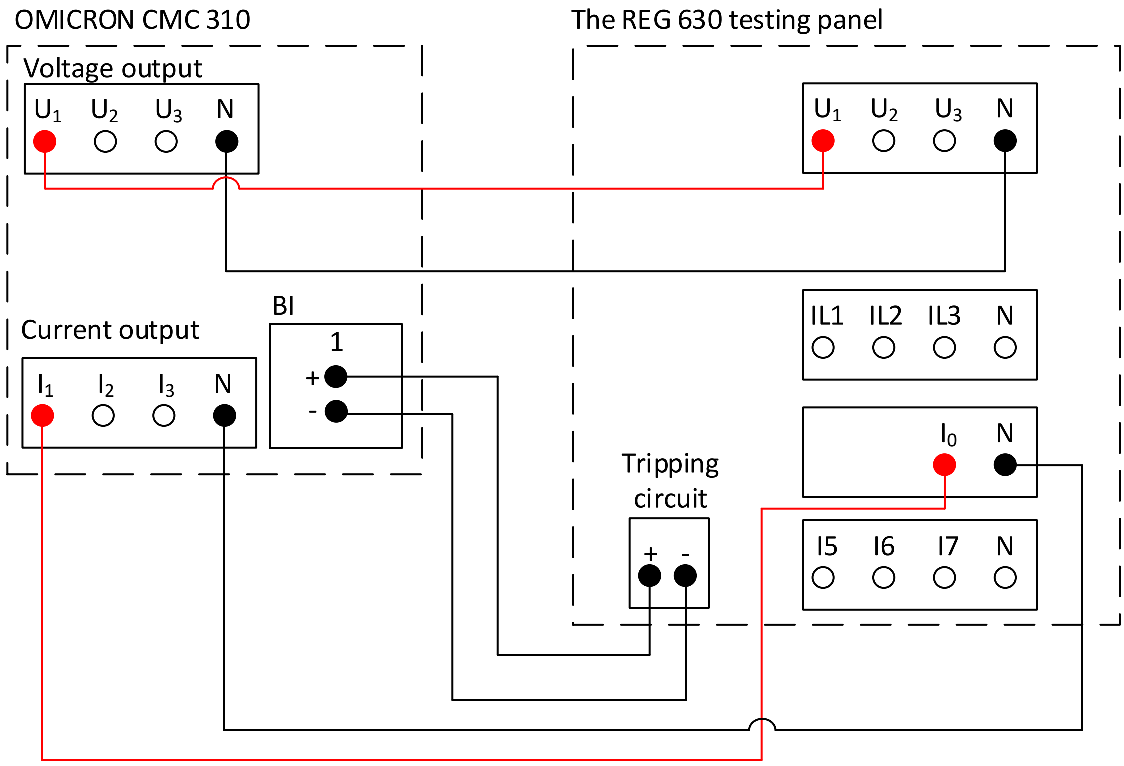


Figure 54 – The wiring diagram for directional earth-fault protection testing

Table 8 presents currents, voltages, and binary signals transcription.

Table 8 - The description of the tester and panel analog and binary IOs

Current / voltage / binary signal name at the tester output	Current / voltage / binary signal name at the testing panel	Description
U1	U1	The secondary voltage of phase A from the terminal side of a generator. Residual voltage is calculated from this value
I1	I0	Residual current, secondary value
+ / -	+ / -	Binary signals for MCB operation recording. Allows to record a time of protection operation at the tester

5.2.5 Directional Earth-Fault Protection Setting

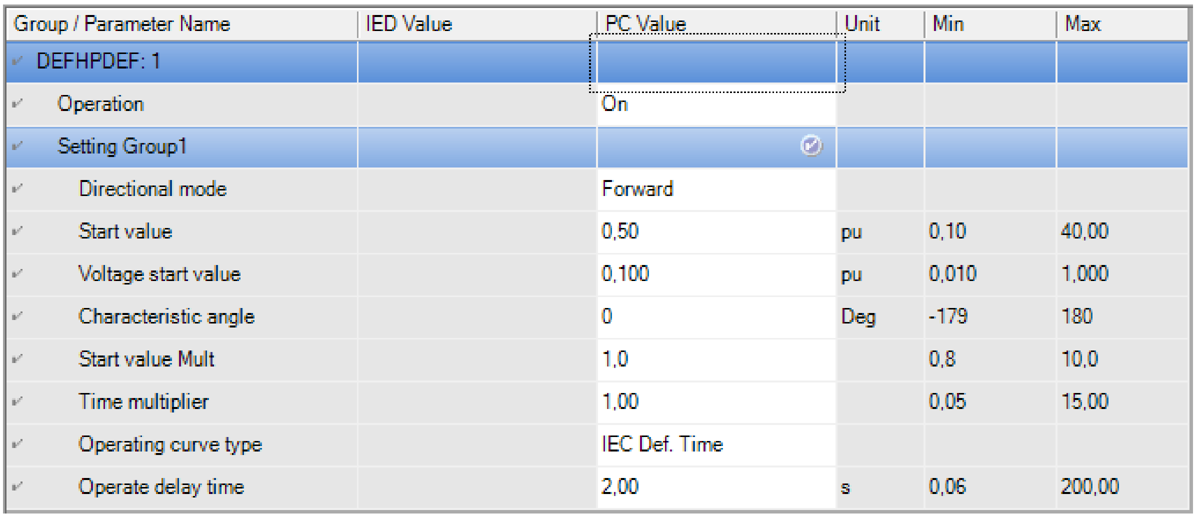
The testing panel has no direct input for residual voltage, thus residual voltage V_0 is calculated from voltages inputs at the generator terminal.

Only one voltage for phase A is injected for the easiest and visible manipulation of the angle between I_0 and V_0.

As it was mentioned in chapter 2.4, directional protection has two function blocks. As for non-directional protection, this type of earth-fault protection has high and low protection stages too. Further settings are applied for the DEFHPDEF function block but might be also applied for the DEFLPDEF function block.

Two types of operating time curves are available for directional earth-fault protection. Only DT operation curve setting was tested.

The protection setting is done in the PCM600 or via LHMI. Protection settings for DT characteristic testing are shown in figure 55.



Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
DEFHPDEF: 1					
Operation		On			
Setting Group1					
Directional mode		Forward			
Start value		0,50	pu	0,10	40,00
Voltage start value		0,100	pu	0,010	1,000
Characteristic angle		0	Deg	-179	180
Start value Mult		1,0		0,8	10,0
Time multiplier		1,00		0,05	15,00
Operating curve type		IEC Def. Time			
Operate delay time		2,00	s	0,06	200,00

Figure 55 - PCM600 configuration for the DEFHPDEF function block, IEC DT operating curve

The advanced protection setting is available at LHMI in the corresponding directional earth-fault protection directory.

The protection zone determined by the settings is shown in figure 56.

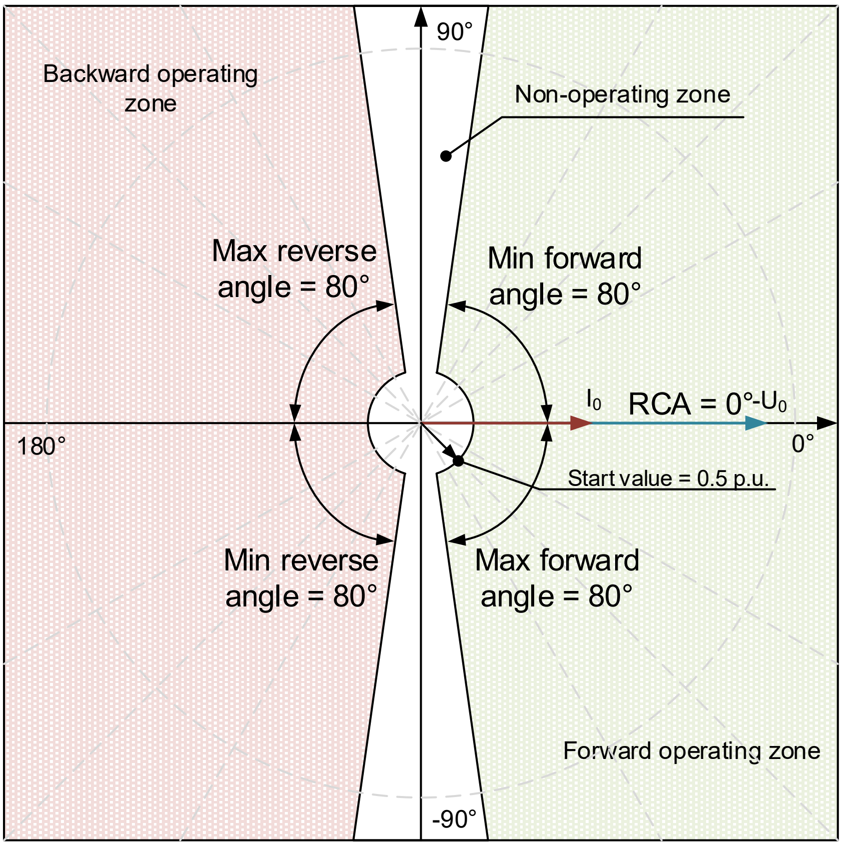


Figure 56 – The directional earth-fault protection operating zone determined by the DEFHPDEF function block setting, IEC DT operation curve

5.2.6 Assignment and Clarification for Directional Earth-Fault Protection Testing

The scope of directional earth-fault protection testing is to check operating zones of the protection, determined by the settings of the DEFHPDEF function block. Five measurement points were chosen for non-operation, forward, and reverse operating zones. Protection trips, whenever the polarizing (voltage), operating (current) values exceed the set limits and angle between them lies in the operating zone.

The rated current is equal to 100A, thus the p.u. values multiplied by 100 will be equal to ampere representation.

OMICRON CMC 310 simulates secondary values of CTs and VTs, but REG 630 calculates primary values by the set ratio. Furthermore, the “Monitoring” and “Measuring” windows at the LHMI of the REG 630 show primary values of the residual current and voltage. If the set rated current is not equal to 100A, the measured value will not be equal to p.u. value multiplied by 100.

The start value is $0.5 \cdot I_n$, i.e. 50A of absolute value. Voltage start value is set as $0.1 \cdot V_{nom\_ph-n}$, i.e. 600V of absolute value. The definite operating time is 2 seconds.

The steps for directional earth-fault protection testing are described below:

1. Make the circuit according to the wiring diagram in Figure 54 for directional earth-fault protection testing.
2. Set the EFHPTOC function block parameters as described in Figure 55.
3. For each measurement point:
    a. Select the injecting secondary residual current value I_0 and its angle. Select the injecting phase A voltage value V_1 and its angle. Assume protection operation.
    b. Inject the set residual current and phase A voltage, write down all required measured parameters to the corresponding table.
4. Check if the measured characteristic matches with the set one.

An example of training completion is presented in chapter 6.2.

5.3 Training Materials for Loss of Excitation Protection

5.3.1 Single Line and Wiring Diagrams for Loss of Excitation Protection Testing

The theoretical principles of the loss of excitation protection were fully described in chapters 1.3 and 2.4.

The single line diagram of the underexcitation protection application is provided in figure 57. This diagram shows the simple application of underexcitation protection in an MV generator.

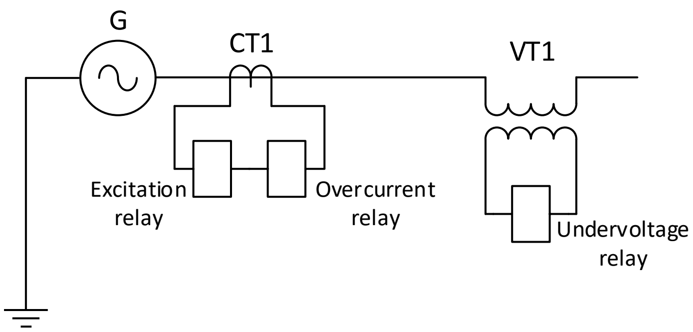


Figure 57 – The single line diagram of loss of excitation protection

The wiring diagram shown in figure 58 describes the connection of OMICRON CMC 310 and the testing panel with the REG 630 for loss of excitation protection testing.

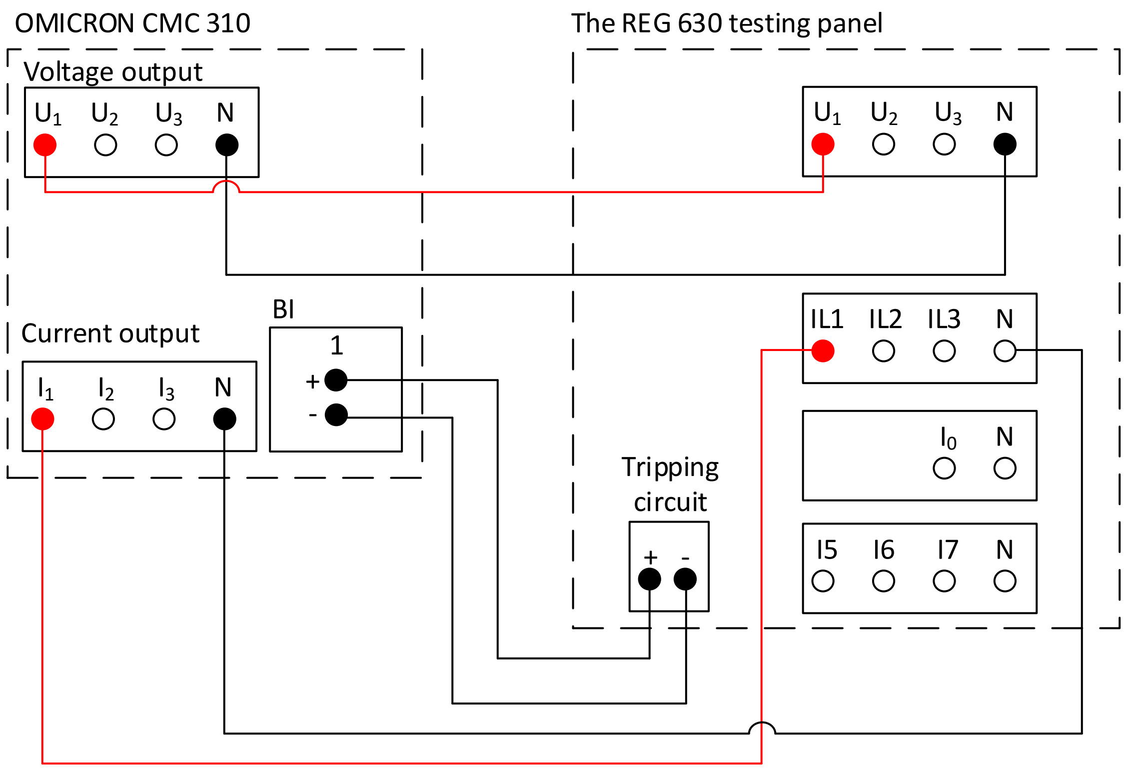


Figure 58 – The wiring diagram for loss of excitation protection testing

Table 9 presents currents, voltages, and binary signals transcription.

Table 9 – The description of the tester and panel analog and binary IOs

Current / voltage / binary signal name at the tester output	Current / voltage / binary signal name at the testing panel	Description
U1	U1	The secondary voltage of phase A from the terminal side of a generator
I1	IL1	Secondary phase A current from the terminal side of a generator
+ / -	+ / -	Binary signals for MCB operation recording. Allows to record a time of protection operation at the tester

5.3.2 Loss of Excitation Protection Setting

The relay has mho characteristic, which can be set via PCM600 or at LHMI. The UEXPDIS function block calculates overall impedance Z1 and its angle Z1_ANGLE from terminal voltages and currents. Secondary current and voltage of phase A only are injected for the easiest manipulation of Z1 and Z1_ANGLE.

Protection settings for loss of excitation protection testing are presented in figure 59.

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
UEXPDIS: 1					
Operation		On			
External Los Det Ena		Enable			
Setting Group1					
Diameter		200	% Zb	1	6000
Offset		-15	% Zb	-1000	1000
Displacement		30	% Zb	-1000	1000
Operate delay time		2,50	s	0,06	200,00

Figure 59 – PCM600 configuration for the UEXPDIS function block

The protection zone determined by the settings is shown in figure 60.

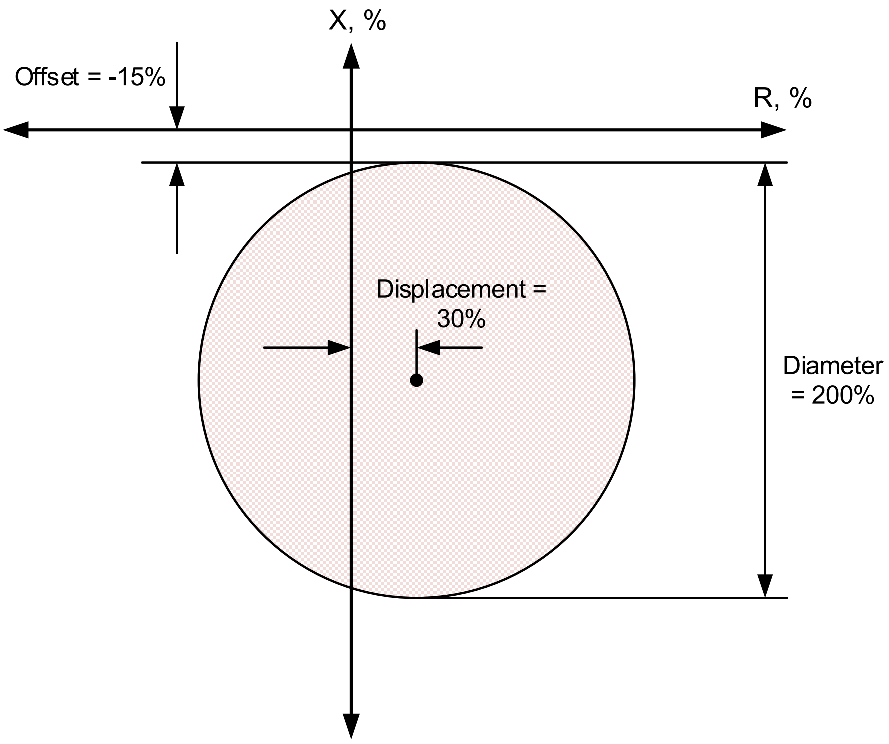


Figure 60 – The mho characteristic of the protection determined by the settings

5.3.3 Assignment and Clarification for Loss of Excitation Protection Testing

The OMICRON CMC 310 simulates secondary values of the generator CTs and VTs. The REG 630 calculates the impedance percentage value based on the measured currents and voltages. During the testing, secondary current and voltage of phase A only were injected. Such an approach allows easy manipulation of impedance angle and module.

Five measurements were done both for the non-operating area and for the operating zone.

The impedance equals 100% when measured current and voltage values are nominal. Impedance angle is the difference between voltage and current angle.

The steps for loss of excitation protection testing are described below:

1. Make the circuit according to the wiring diagram in Figure 58 for loss of excitation protection testing.
2. Set the UEXPDIS function block parameters as described in Figure 59.
3. For each measurement point:
    a. Select and set the injecting current and voltage values and their angles at OMICRON CMC 310 screen. Suggest protection operation.
    b. Inject current and voltage. Write down the required data to a corresponding table.
4. Check if the set operating zone corresponds with the measurement results.

An example of training completion is presented in chapter 6.3.

6 Protection Functionalities Testing

Further chapters are dedicated to the description of the training process and they demonstrate the results of protection testing.

Each subparagraph is dedicated to specific protection. The information described in the following subparagraphs covers measurement results, protection operation summary, and experiments outputs. The content of each subparagraph in general terms as follows:

1. Tables with the testing results and their description.
2. Examples of calculations are described in chapter 5.
3. Graphs illustrate the measurement points.

6.1 Differential Protection Testing

The first section of the operational characteristic of the differential protection is described by the following parameters:

- The bias current limit is 40% of the rated current or 40A;
- The operating current is 20% of the rated current or 20A;

The measurement results are presented in table 10.

Table 10 – The results of the differential protection testing at the first section

№	I_1*	I_{1_angle}	I_2	I_{2_angle}	I_{diff}**	I_{diff_calc}	I_{bias}**	$I_{bias\ calc}$	Protection operate	Operate time
1	0.05	0	0.05	180	0.080	0	5.025	5	No	-
2	0.12	-34	0.1	150	2.143	2.141	11.015	10.993	No	-
3	0.25	35.6	0.2	208	5.779	5.812	22.519	22.451	No	-
4	0.308	62.5	0.326	253.2	6.122	6.1771	31.635	31.562	No	-
5	0.386	19.7	0.354	215.2	10.486	10.471	36.741	36.663	No	-
6	0.39	10.2	0.415	165.2	17.658	17.5935	39.348	39.2968	No	-
7	0.15	15	0.1	35	24.623	24.636	3.302	3.82	Yes	0.553
8	0.125	0	0.113	60	20.610	20.6201	11.024	5.9726	Yes	0.0525
9	0.195	-46.3	0.27	195	24.582	24.5678	20.112	20.0931	Yes	0.0549
10	0.216	-52.3	0.398	152.6	22.094	22.160	30.110	30.042	Yes	0.0555
11	0.386	12.6	0.364	138	34.519	34.454	33.407	33.327	Yes	0.0569

*secondary values

**primary values

The measuring and calculation procedure is shown for an example of number 4 measurement. The following steps are described in chapter a.

<u>Step 1</u>. *Select the I_1 and I_2 injecting secondary currents and their electrical angles and calculate relevant differential and bias currents using the equations [1] and [2].*

All calculations were done in Mathcad software. An example of necessary calculations is shown in figure 61.

$I_1 := 0,308 \qquad I_2 := 0,326$

$angle_1 := 62,5 \qquad angle_2 := 253,2$

$a_1 := e^{i \cdot angle_1 \, °} = 0,4617 + 0,887 \cdot i$

$a_2 := e^{i \cdot angle_2 \, °} = -0,289 - 0,9573 \cdot i$

$I_{diff} := \left|\left(I_1 \cdot a_1 + I_2 \cdot a_2\right)\right| \cdot 100 = 6,1771$

$I_{bias} := \dfrac{\left|I_1 \cdot a_1 - I_2 \cdot a_2\right|}{2} \cdot 100 = 31,562$

Figure 61 – Calculations of bias and differential currents based on chosen input secondary currents I_1 and I_2, and their angles

The results of calculations should be written in the corresponding column of Table 10.

Step 2. *Compare calculated bias current with defined operation characteristic section and compare calculated differential current with set operation current related to the section. Make an assumption whether protection will trip or not.*

The calculated bias current is within section 1, the calculated differential current is less than the operation value of 20A, and thus protection will not operate.

Step 3. *Inject the chosen I_1 and I_2 currents via the tester. Write down all the required parameters to the corresponding operation result table*

To inject the current, further steps need to be done:

1. Fill in currents parameters at the tester's screen as shown in figure 62.
2. Inject currents by pushing the I/O button. I/O button should change the light from green to red.

Change of parameter values at the OMICRON CMC 310 screen is available by tapping the "NUMPAD" button or using the operation circle.

Figure 62 – The OMICRON screen for currents and voltages injection

After protection testing, the measured values will be available at the LHMI in the "Measurement" directory. The screen with measured values is shown in figure 63.

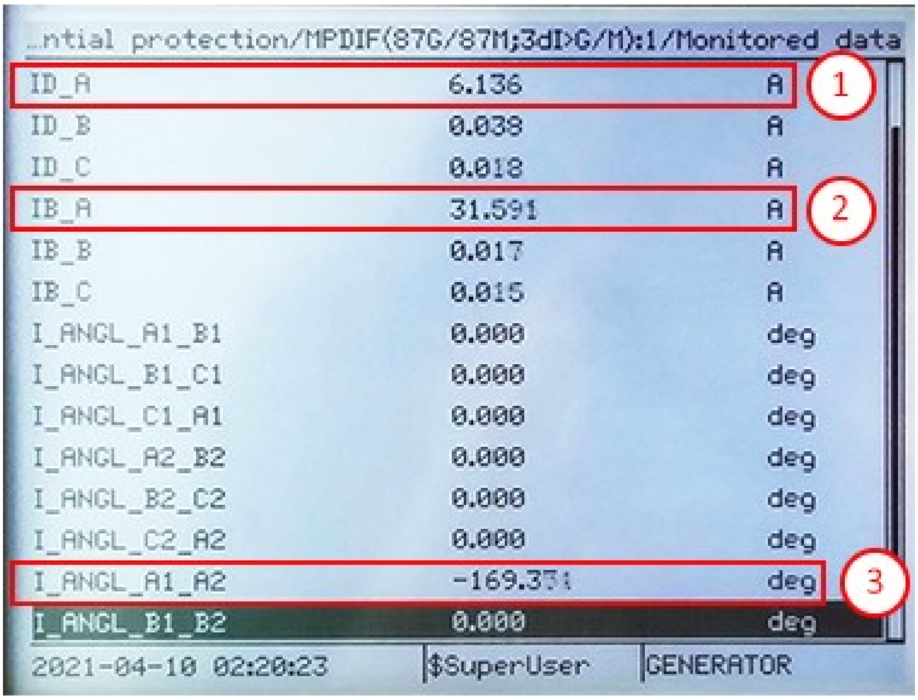


Figure 63 – The REG 630 LHMI "Measurement" screen; 1 is a measured differential current in phase A; 2 is a measured bias current in phase A; 3 is an angle between measured current I_1 and I_2

If protection trips, it is recognizable by a typical clicking sound and red "TRIP" LED at the front side of the REG 630. The time of protection operation is available at the OMICRON CMC 310 screen, as shown in figure 64.

Figure 64 – The screen of OMICRON CMC 310 if the differential protection trips

After the current injection, the measured parameters should be written in the corresponding table. Changing the currents is only allowed when the injection is stopped, i.e. I/O button at the tester has a green light.

The measurement results for section 2 and section 3 are shown in tables 11 and 12 respectively.

Table 11 – The results of the differential protection testing at the second section

№	I_1*	I_{1_angle}	I_2	I_{2_angle}	I_{diff}**	I_{diff_calc}	I_{bias}**	$I_{bias\ calc}$	Protection operate	Operate time
1	0.42	15.6	0.4	196.4	2.145	2.080	41.047	40.999	No	-
2	0.58	0.65	0.568	179.86	1.476	1.438	57.408	57.399	No	-
3	0.75	32.5	0.73	-162	18.757	18.783	73.538	73.410	No	-
4	0.88	15.2	0.863	-168.9	6.523	6.462	87.233	87.094	No	-
5	1.08	18.34	1.15	-157	11.468	11.450	111.615	111.408	No	-
6	0.456	48.6	0.689	-175.6	48.218	48.184	53.339	53.225	Yes	0.0578
7	0.986	35.2	0.608	164	76.932	76.849	72.481	72.339	Yes	0.0536
8	0.96	15.7	0.76	178	33.08	33.0267	85.128	84.9901	Yes	0.0557
9	1.29	35.2	0.98	138	143.874	143.678	89.402	89.228	Yes	0.0554
10	1.15	12.2	0.956	162.8	56.704	56.640	102.106	101.883	Yes	0.0521
11	1.2	41.8	1.18	180	85.028	84.9242	111.392	111.171	Yes	0.0569

Table 12 – The results of the differential protection testing at the third section

№	I_1*	I_{1_angle}	I_2	I_{2_angle}	I_{diff}**	I_{diff_calc}	I_{bias}**	$I_{bias\ calc}$	Protection operate	Operate time
1	1.4	5.68	1.38	-175.6	3.716	3.6935	139.275	138.9913	No	-
2	1.6	10	1.78	-172.8	53.585	53.5849	167.444	167.1052	No	-
3	1.93	-18.3	1.8	156.8	20.469	20.5652	186.717	186.3297	No	-
4	2.2	-2.9	2.08	159.3	67.315	67.269	211.848	211.4254	No	-
5	2.8	-10	2.95	155	76.640	76.5118	285.670	285.0421	No	-
6	1.35	15.6	1.56	148	119.155	118.9932	133.494	133.194	Yes	0.0548
7	1.93	38.9	1.32	198	84.272	84.1036	160.181	159.9004	Yes	0.0563
8	2.42	15.4	2.25	145.6	197.62	197.227	212.295	211.825	Yes	0.0552
9	2.86	22.5	2.56	143.1	270.390	269.8	236.083	235.5164	Yes	0.0578
10	3.43	56.5	3.84	169.1	405.615	404.8115	303.226	302.6292	Yes	0.0553

The measurement and calculation procedure is the same as in section 1. The calculated differential current should be compared with the calculated set operation current. An example of the calculation is given in figure 65.

$$I_1 := 0,986 \qquad I_2 := 0,608$$

$$angle_1 := 35,2 \qquad angle_2 := 164$$

$$a_1 := e^{i \cdot angle_1 \,°} = 0,8171 + 0,5764 \cdot i$$

$$a_2 := e^{i \cdot angle_2 \,°} = -0,9613 + 0,2756 \cdot i$$

$$I_{diff} := \left|\left(I_1 \cdot a_1 + I_2 \cdot a_2\right)\right| \cdot 100 = 76,849$$

$$I_{bias} := \frac{\left|I_1 \cdot a_1 - I_2 \cdot a_2\right|}{2} \cdot 100 = 72,3385$$

$$I_{2operate} := 20 + \left(I_{bias} - 40\right) \cdot 0,25 = 28,0846$$

$$I_1 := 1,93 \qquad I_2 := 1,32$$

$$angle_1 := 38,9 \qquad angle_2 := 198$$

$$a_1 := e^{i \cdot angle_1 \,°} = 0,7782 + 0,628 \cdot i$$

$$a_2 := e^{i \cdot angle_2 \,°} = -0,9511 - 0,309 \cdot i$$

$$I_{diff} := \left|\left(I_1 \cdot a_1 + I_2 \cdot a_2\right)\right| \cdot 100 = 84,1036$$

$$I_{bias} := \frac{\left|I_1 \cdot a_1 - I_2 \cdot a_2\right|}{2} \cdot 100 = 159,9004$$

$$I_{3operate} := 20 + 80 \cdot 0,25 + \left(I_{bias} - 120\right) = 79,9004$$

Figure 65 – An example of differential and bias current calculations for section 2 and section 3

The graphical illustration of protection testing is shown in the figures below.

Figures 66, 67, and 68 illustrate each section of protection characteristic, figure 69 shows an overall view of protection characteristic and tested points. Points when protection operated are colored with green, points when protection did not operate are colored with green. In Figure 69, the color of the point corresponds with the section number.

Therefore, differential protection has been tested. According to the results of the test, each calculated point corresponds to the tested point. Calculated values fully match the measured data. No false protection operation has been noted, as no misoperation was caught. The set operation characteristic meets the measured values.

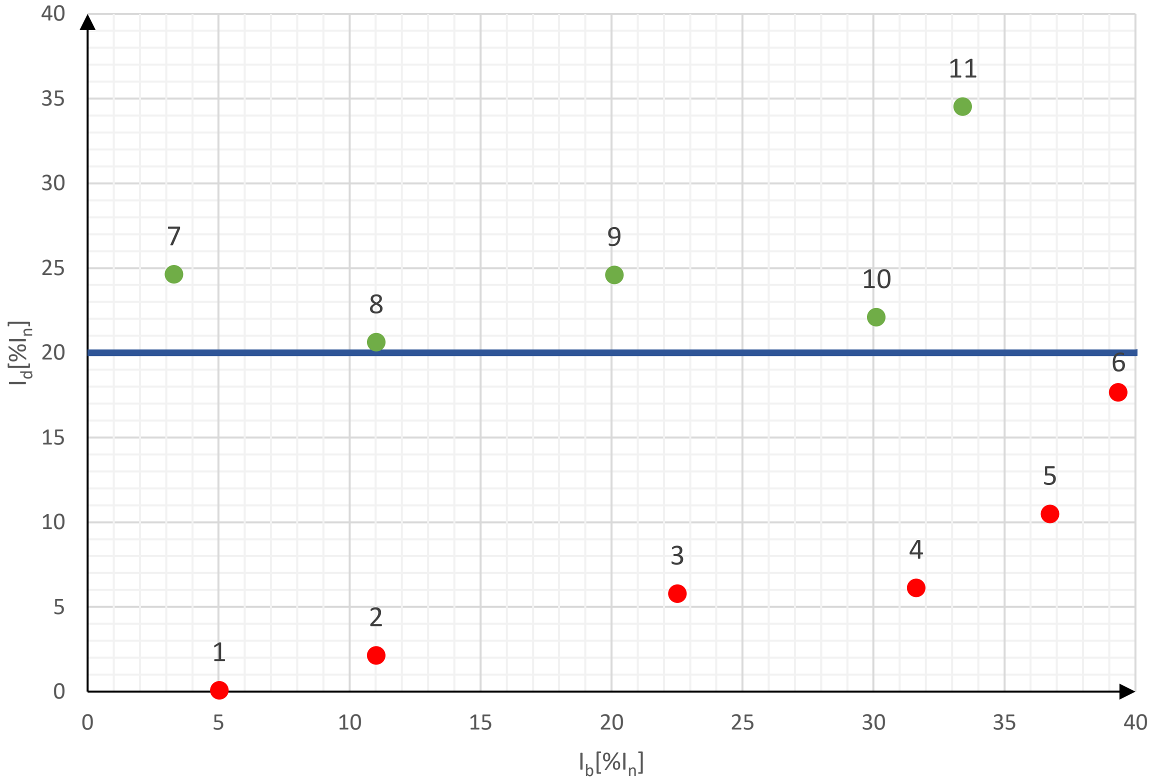


Figure 66 – Section 1 of differential protection testing graph

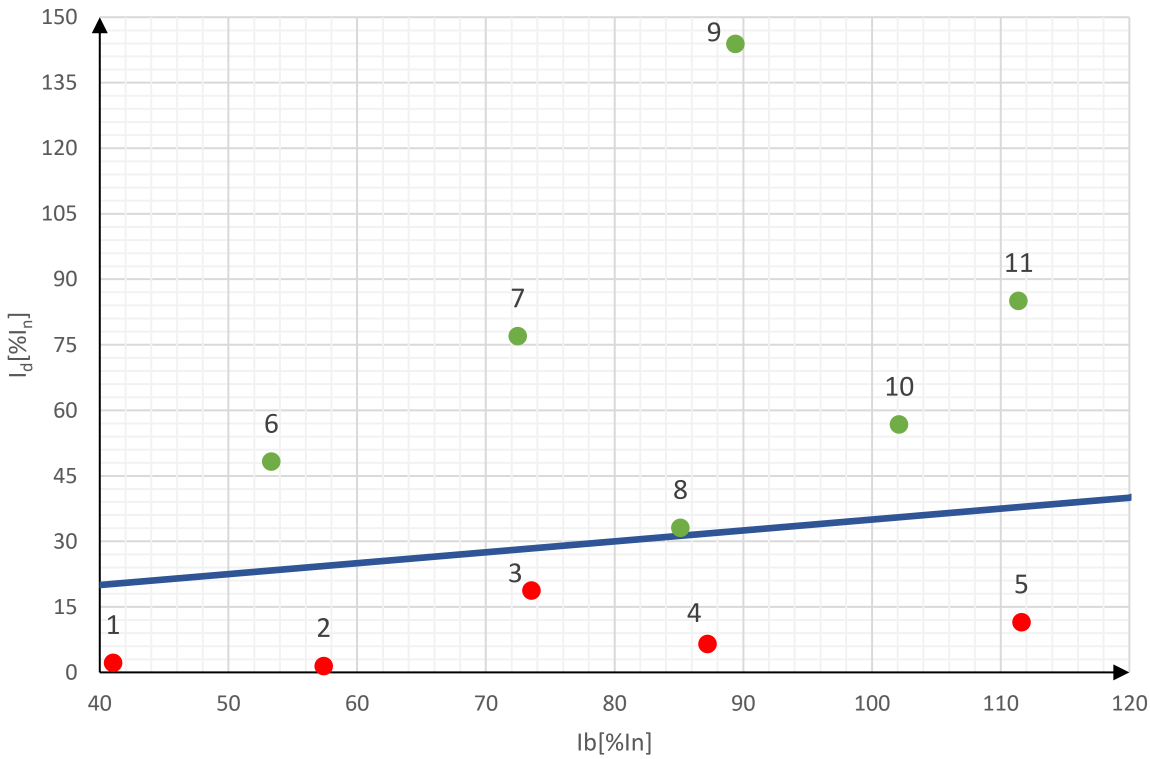


Figure 67 – Section 2 of differential protection testing graph

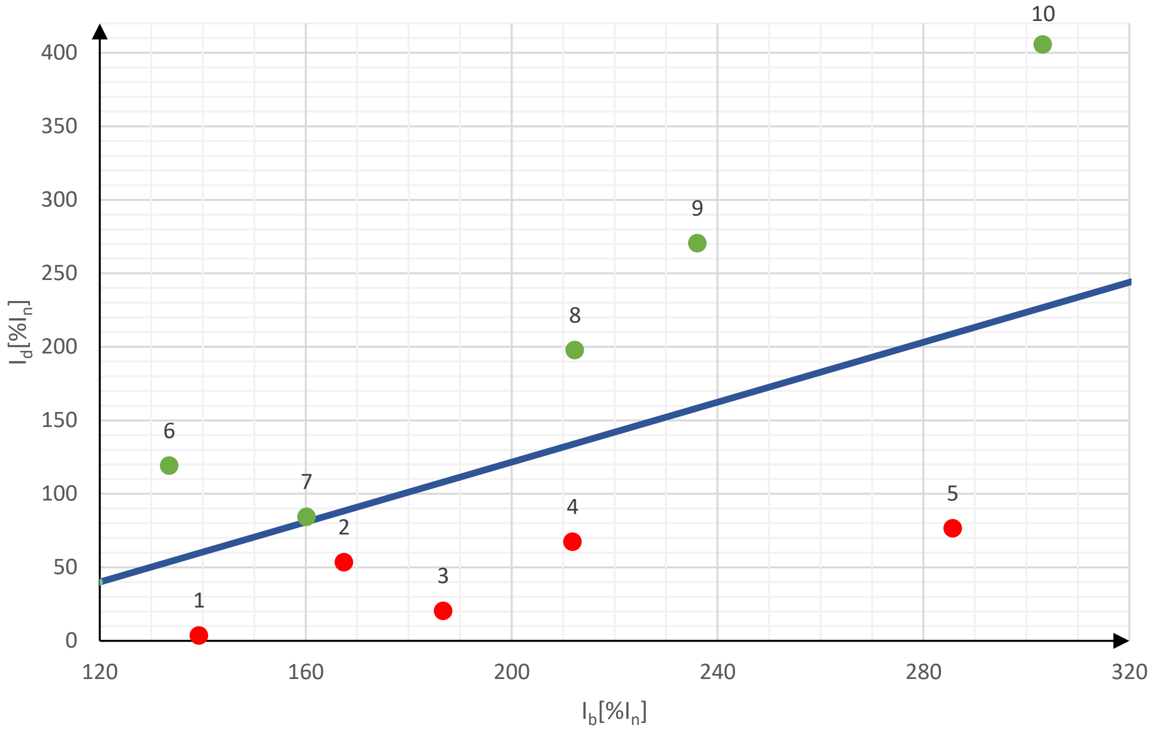


Figure 68 – Section 3 of differential protection testing graph

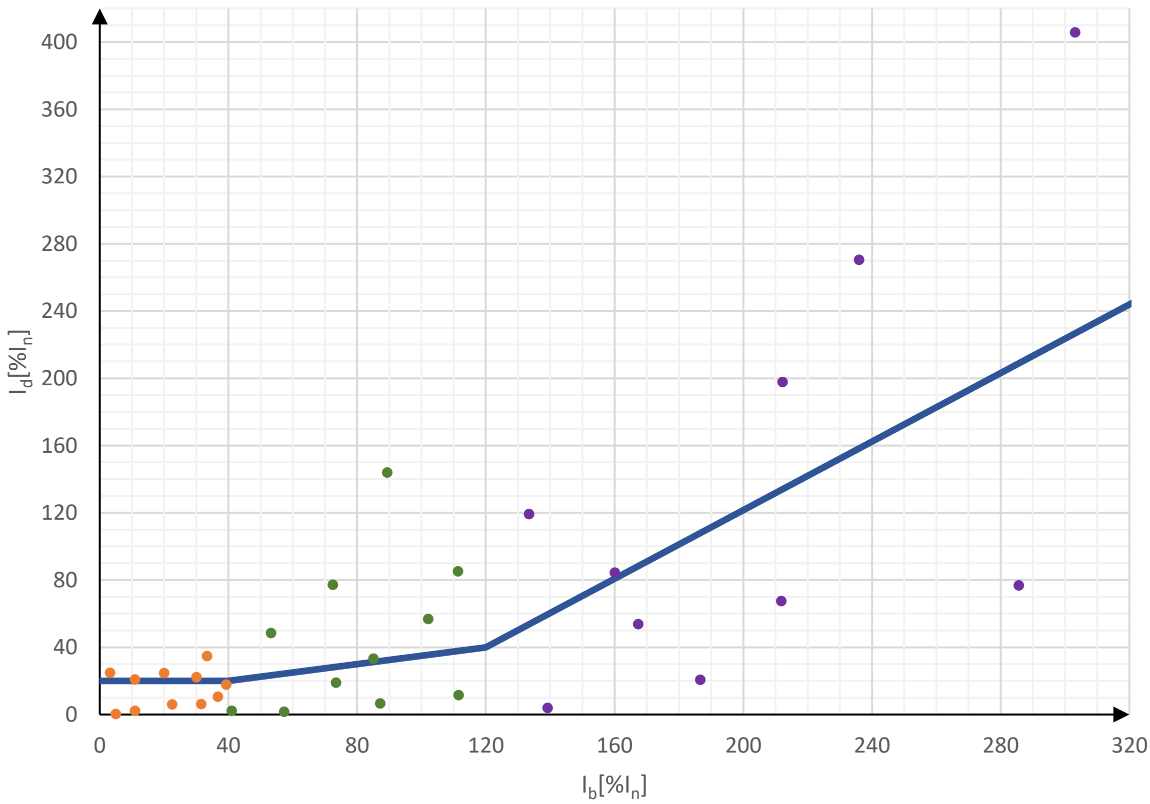


Figure 69 – The differential protection function block MPDIF testing graph

6.2 Earth-Fault Protection Testing

6.2.1 Non-Directional Earth-fault Protection Testing

Two types of operation curve parameters were tested: definite time (DT) characteristic and IEC normal inverse (IDMT) characteristic.

The measurement results of DT curve testing are presented in table 13.

Table 13 – The results of non-directional earth-fault protection testing, DT operating curve

№	I_0 injected*	I_{0_ampl}**	I_{0_RMS}**	I_{0_PTOP}**	Protection operation	Time of operation
1	0.1	10.088	10.093	10.09	No	-
2	0.25	25.129	25.092	25.01	No	-
3	0.35	35.032	35.072	34.98	Yes	2.0184
4	0.85	85.209	85.183	253.2	Yes	2.0067

*secondary values

**primary values

The REG 630 has several measurement modes for residual current. The measurement mode can be selected in the settings.

The measuring procedure is shown for the example of measurement 3. The following steps are described in chapter 5.2

Steps 1 and 2. *Select the injecting secondary residual current value I_0 and its angle. Inject the set residual current, write down all required data to Table 13.*

As the DT characteristic is in the test, expected operating time is 2 seconds.

The injection of residual current and operating time measurement results are shown in Figure 70.

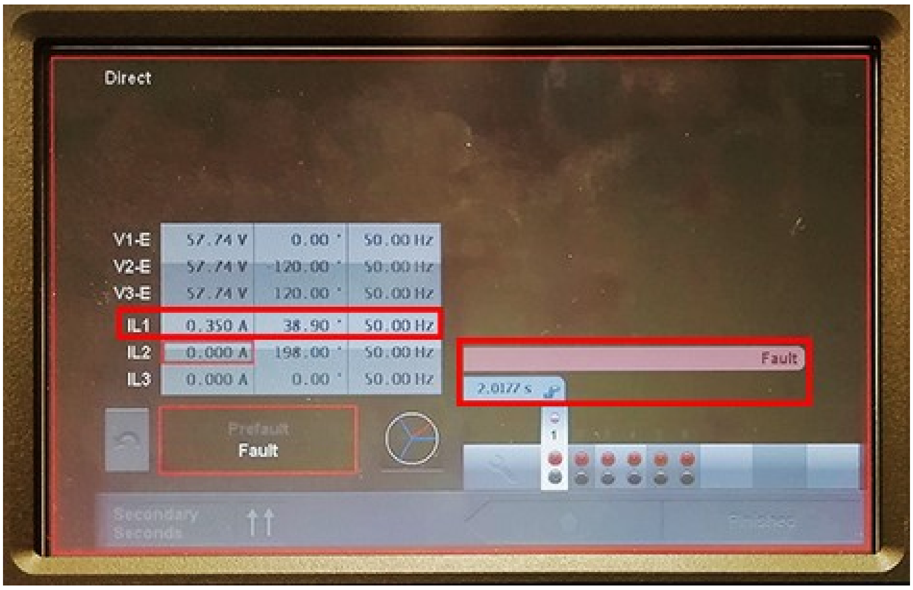


Figure 70 – The screen of OMICRON CMC 310 if the non-directional earth-fault protection trips, DT curve

The results of the current measurement are available on the REG 630 LHMI, as shown in Figure 74.

The measurement result for DT operating curve testing is shown in figure 71. The set characteristic is also drawn in the same figure. Points, where protection has operated, are colored with green, where not – with red.

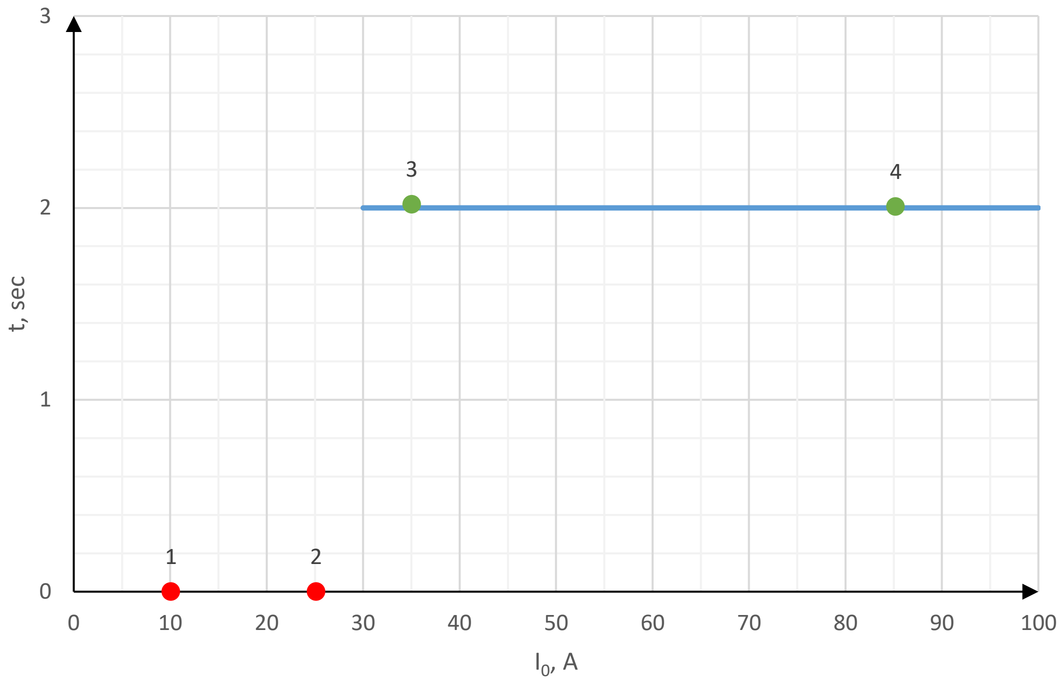


Figure 71 – The resulting graph of non-directional earth-fault protection testing, DT curve

Points 1 and 2 are located in a non-tripping zone, thus protection did not operate in those points. The operating time for points 3 and 4 is close to the set characteristic, thus, the relay protection settings correspond to measured values. Protection is adjusted properly.

The measurement results of IDMT curve testing are presented in table 14.

Table 14 - The results of non-directional earth-fault protection testing, IDMT operating curve

№	I_0 injected*	I_{0_ampl}**	I_{0_RMS}**	I_{0_PTOP}**	Protection operation	Time of operation	Calculated time
1	0.4	40.045	40.105	39.880	No	-	-
2	0.6	60.118	60.136	59.787	No	-	-
3	0.8	80.153	80.148	79.330	No	-	-
4	0.9	90.170	90.151	89.742	No	-	-
5	0.95	95.227	95.147	95.09	No	-	-
6	1.2	120.214	120.175	120.155	Yes	37.9634	38.3237
7	2	200.429	200.426	200.328	Yes	10.169	10.029
8	3.5	350.829	350.814	346.599	Yes	5.5298	5.5179
9	5	501.164	501.189	495.112	Yes	4.2921	4.2797
10	7	701.656	701.595	694.181	Yes	3.5392	3.5277

*secondary values

**primary values

The measuring procedure is shown for the example of measurement 7. The following steps are described in chapter 5.2

<u>Step 1</u>. *Select the injecting secondary residual current value I_0 and its angle. Calculate the expecting operating time using the equation* [8]

The injection of residual current and operating time measurement results are shown in Figure 72.

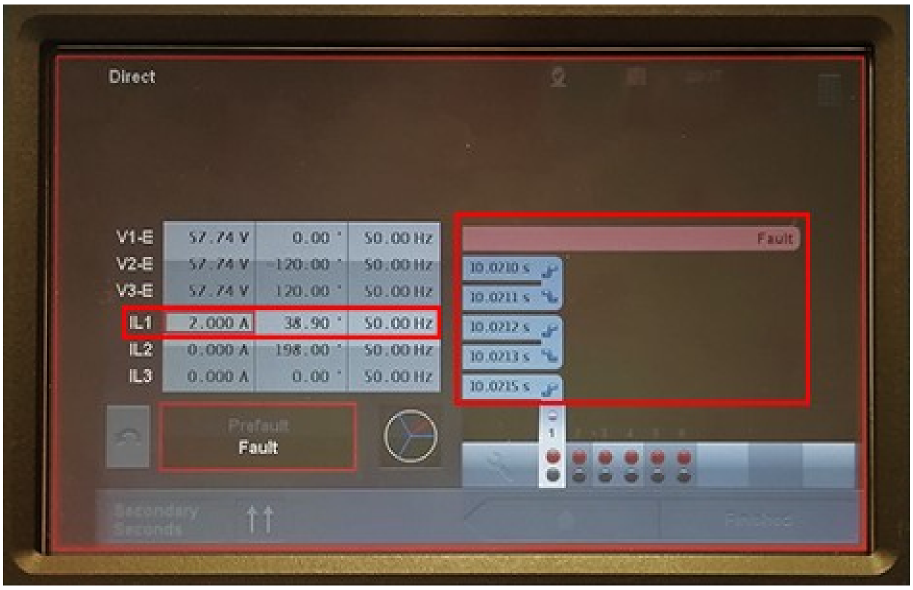


Figure 72 - The screen of OMICRON CMC 310 if the non-directional earth-fault protection trips, IDMT curve

The operating time calculation is done by the equation [8]. The example of the calculation is given in Figure 73. All calculations were done in Mathcad software.

$$A := 0{,}14 \qquad B := 0 \qquad C := 0{,}02 \qquad k := 1 \qquad I_{fault} := 200 \qquad I_{set} := 100$$

$$t := \left(\frac{A}{\left(\frac{I_{fault}}{I_{set}} \right)^{C} - 1} + B \right) \cdot k = 10{,}029$$

Figure 73 – Calculation of non-directional earth-fault protection operating time, IDMT curve

The calculation result should be written in the corresponding column in Table 14.

The results of the current measurement are available on the REG 630 LHMI, as shown in Figure 74.

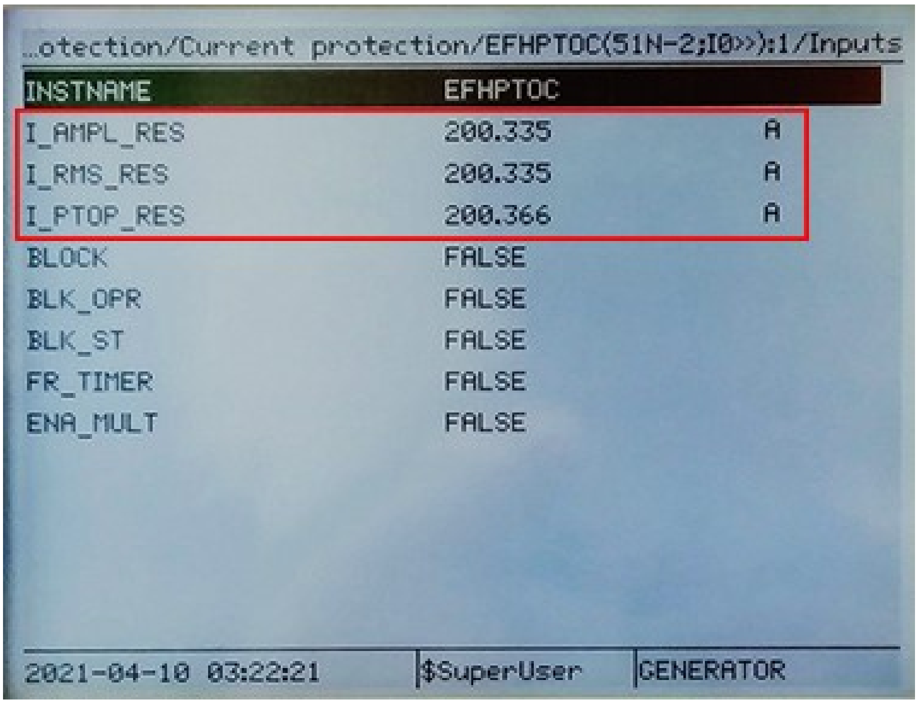


Figure 74 – The REG 630 LHMI "Measurement" screen; Red rectangle shows the residual current measurements

The measurement result for IDMT operating curve testing is shown in Figure 75. The set characteristic is also drawn in the same figure. Points, where protection has operated colored with green, where not – with red.

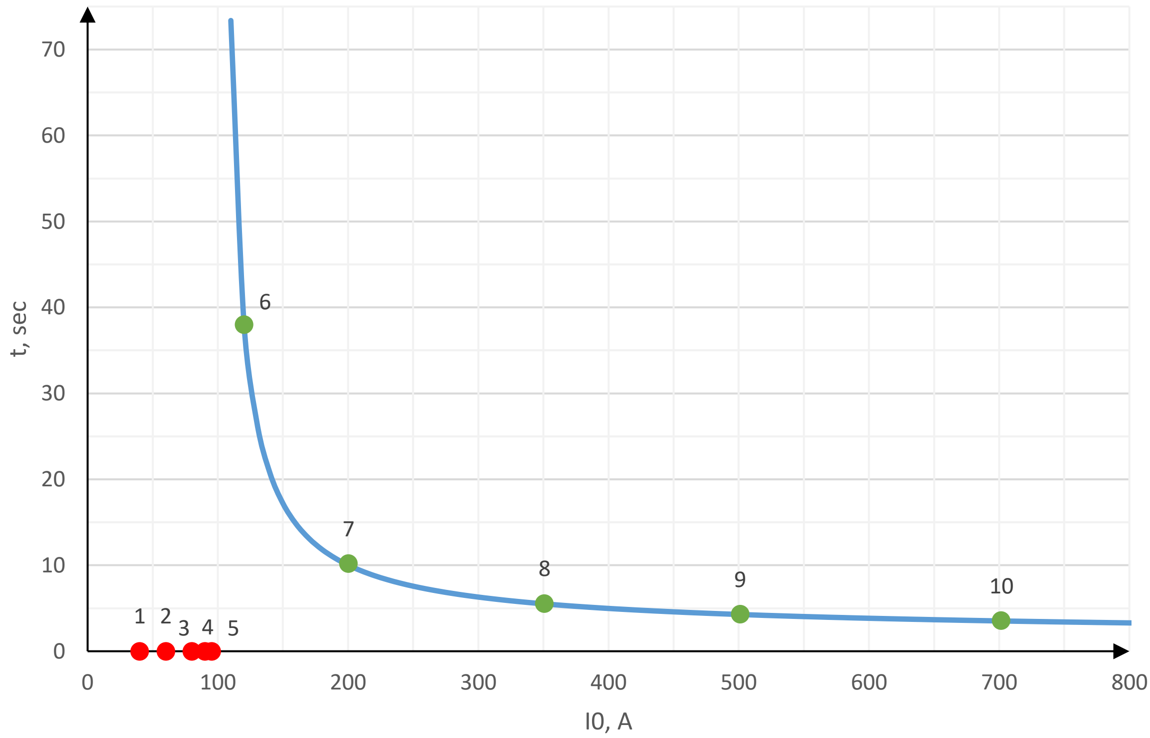


Figure 75 – The resulting graph of non-directional earth-fault protection testing, IDMT curve

Points 1-5 are located in a non-tripping zone, thus protection did not operate in those points. The operating time for points 6-10 is close to the set characteristic, thus, the relay protection settings correspond to measured values. Protection is adjusted properly.

6.2.2 Directional Earth-Fault Protection Testing

Despite the fact that there are two operating curves available, only the DT curve was tested, because it is sufficient for directional earth-fault protection testing.

The main parameter of the operating zone is the relay characteristic angle (RCA). This parameter represents the angle between I_0 and U_0, in the real case, this angle is dependent on the grounding system of the generator. For testing purposes the RCA = 0°, which represents the simplest case of directional protection and sufficient for initial training.

The measurement results of directional protection are presented in Table 15.

Table 15 - The results of directional earth-fault protection testing, DT operating curve

№	$I_{0\_injected}$*	$I_{0\_inj\_angle}$	$I_{0\_ampl\_RES}$**	U_{A_inj}*	$U_{A\_inj\_angle}$	$U_{0\_ampl\_RES}$	The angle between U_0 and I_0	Prot. operation	Time of operation
1	0.1	0	10.138	1	0	36.223	0	No	-
2	0.8	93.4	80.245	20.65	0	750.943	-93.302	No	-
3	0.98	15	98.224	20.65	186	750.916	171.063	No	-
4	1.23	14	123.32	24.7	102	898.407	88.052	No	-
5	0.78	-28	78.211	22.6	-115	821.926	-86.89	No	-
6	0.936	23	93.805	20.05	86	729.077	63.106	Yes	2.082
7	1.087	42.9	108.909	25.68	60.85	934.083	18.015	Yes	2.036
8	0.532	60.85	53.345	19.1	60.85	694.540	0.072	Yes	2.025
9	1.536	51.6	153.97	27.68	23.2	1006.906	-28.39	Yes	2.013
10	1.294	75.6	129.737	24.8	3	901.958	-72.552	Yes	2.005
11	0.936	31.6	93.823	20.05	145.4	729.036	113.925	Yes	2.059
12	1.087	28.3	108.654	25.68	184.7	934.187	156.467	Yes	2.033
13	0.532	16	53.245	19.1	196	694.152	-179.985	Yes	2.042
14	1.536	38.1	153.785	27.68	-98	1005.98	-136.064	Yes	2.018
15	1.294	8.15	129.456	24.8	-98	901.125	-106.11	Yes	2.029

*secondary values

**primary values

The values marked with blue – are for the non-operating zone, green – for the forward operating zone, red – for the reverse operating zone.

The measuring procedure is the same as for the non-directional earth-fault protection testing, except the secondary voltage of phase A should be injected for residual voltage calculation.

The resulting graph for directional earth-fault protection testing is shown in figure 76.

The protection operating zone is defined by the "Operating zone" parameter in the PCM600 settings. Protection trips when the values of I_0 and U_0 exceed the set limit and angle between the polarizing and operating quantities lays in the operating direction. The vector coding in Figure 76 has the same color as the measurement in Table 15. According to the resulting graph, measured values fully correspond to the set parameters, which indiccates the correct operation of the DEFHPDEF function block.

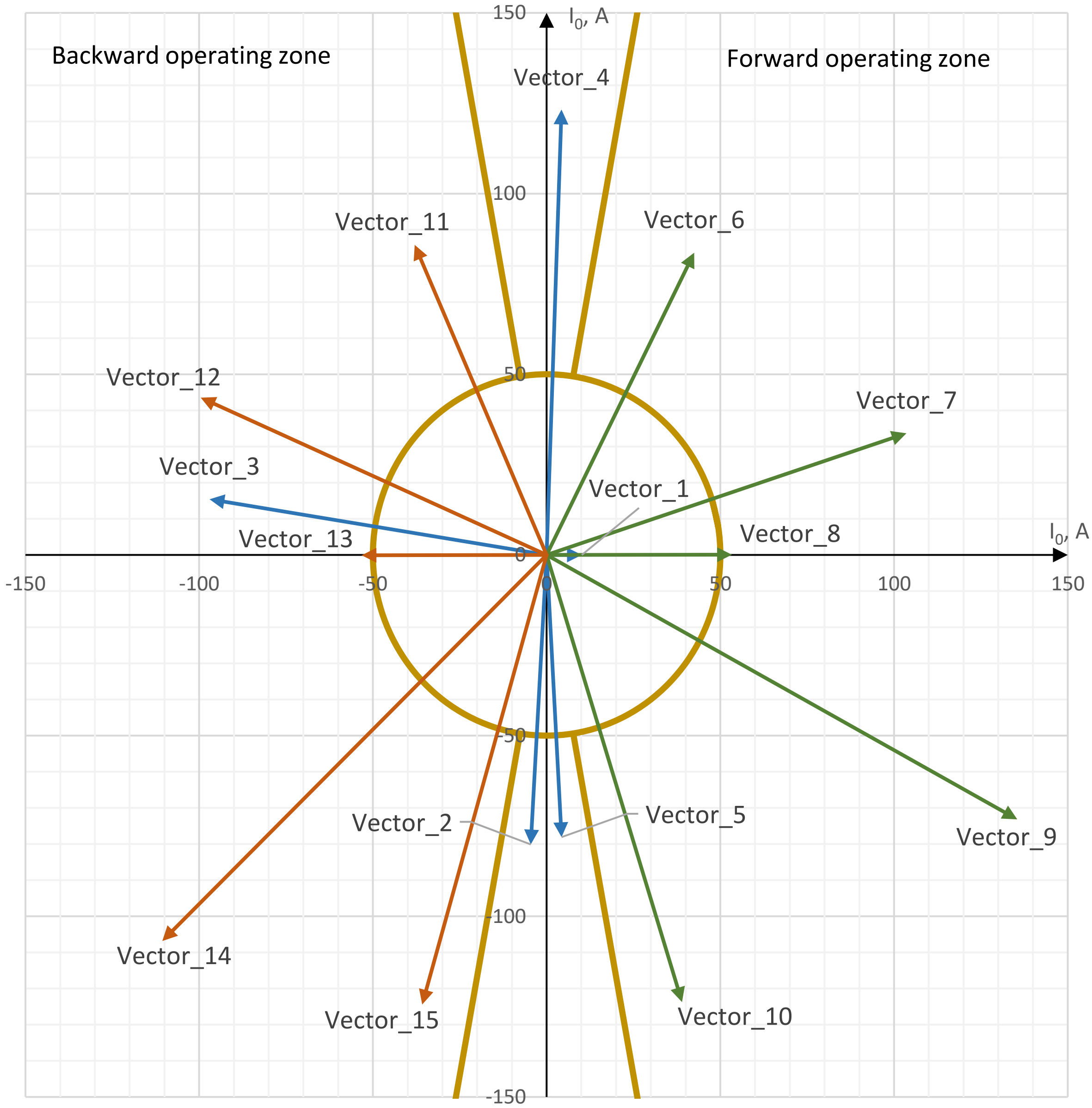


Figure 76 - The resulting graph of directional earth-fault protection testing

6.3 Loss of Excitation Protection Testing

Protection operates with the time delay set in the PCM600. For protection testing, a time delay of 2.5 seconds was chosen.

Secondary values of phase A current and voltage are injected into the REG 630. 1A of the secondary current is equal to 100A of primary current value, 57.74V of secondary voltage is equal to 12kV of primary voltage.

The measurement results of the loss of excitation protection are presented in Table 16.

Table 16 - The results of the loss of excitation protection testing

№	I_A injected	I_{A_angle}	U_A injected	U_{A_angle}	$Z1_{meas}$, %	Z1 angle, deg	Protection operation	Time of operation
1	1	0	57.74	0	99.9	0.018	No	-
2	0.85	-35.1	57.74	0	117.5	35.038	No	-
3	1.011	-123.45	46.54	14.6	79.7	137.896	No	-
4	0.353	23.7	60.43	-84.95	296.8	-108.579	No	-
5	1.467	153.5	11.6	113.1	13.6	-40.221	No	-
6	0.3	7.05	29.38	-42.65	169.3	-49.733	Yes	2.5136
7	1.751	14	27.86	-78.75	27.5	-92.625	Yes	2.5177
8	0.732	35.55	51.96	-84.95	122.8	-120.534	Yes	2.5328
9	0.606	-4.25	64.82	-63.9	185.2	-59.743	Yes	2.5166
10	1.67	55.05	50.34	-68.95	52.1	-124.046	Yes	2.5067

The measuring procedure is shown for the example of measurement 2. The following steps are described in chapter 5.3.

Steps 1 and 2. *Select and set the injecting current and voltage values and their angles at OMICRON CMC 310 screen. Suggest protection operation. Inject current and voltage. Write down the required data to a corresponding table.*

The injection of phase A current and voltage is shown in figure 77.

Figure 77 – The screen of OMICRON CMC 310 with current and voltage injection

The results of the current measurement are available on the REG 630 LHMI, as shown in figure 78.

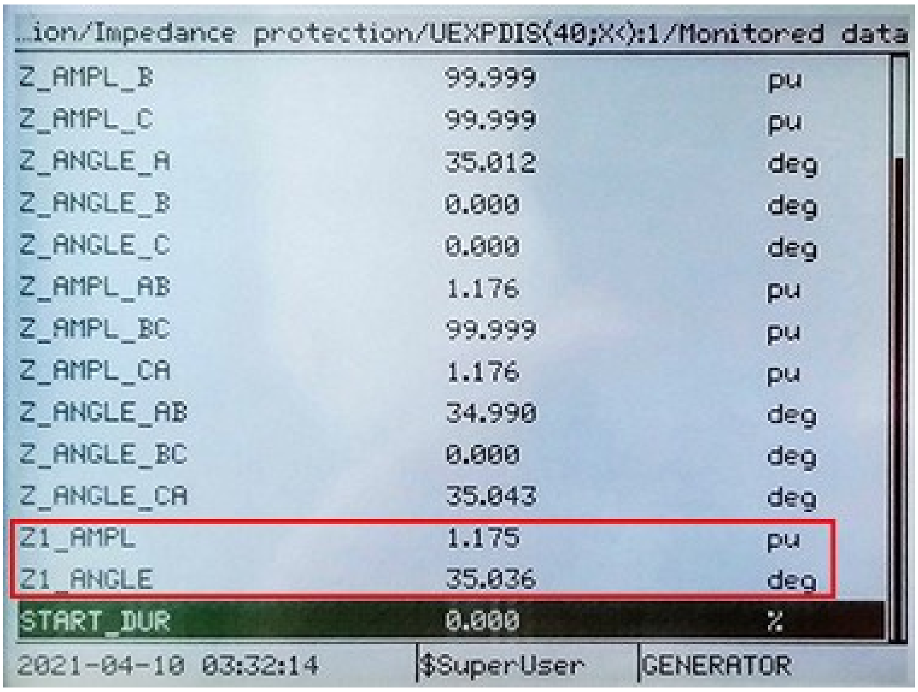


Figure 78 – The REG 630 LHMI "Measurement" screen; Red rectangle shows the impedance measurements

The measurement result for loss of excitation protection testing is shown in figure 79. The operating zone is determined by the yellow circle. The vectors represent the data from Table 16. Vectors 1-5 are colored with blue and represent the non-operating points, vectors 6-10 are colored with green and represent the operating point of the UEXPDIS function block. The measured result fully corresponds to set protection parameters, thus the test went successfully.

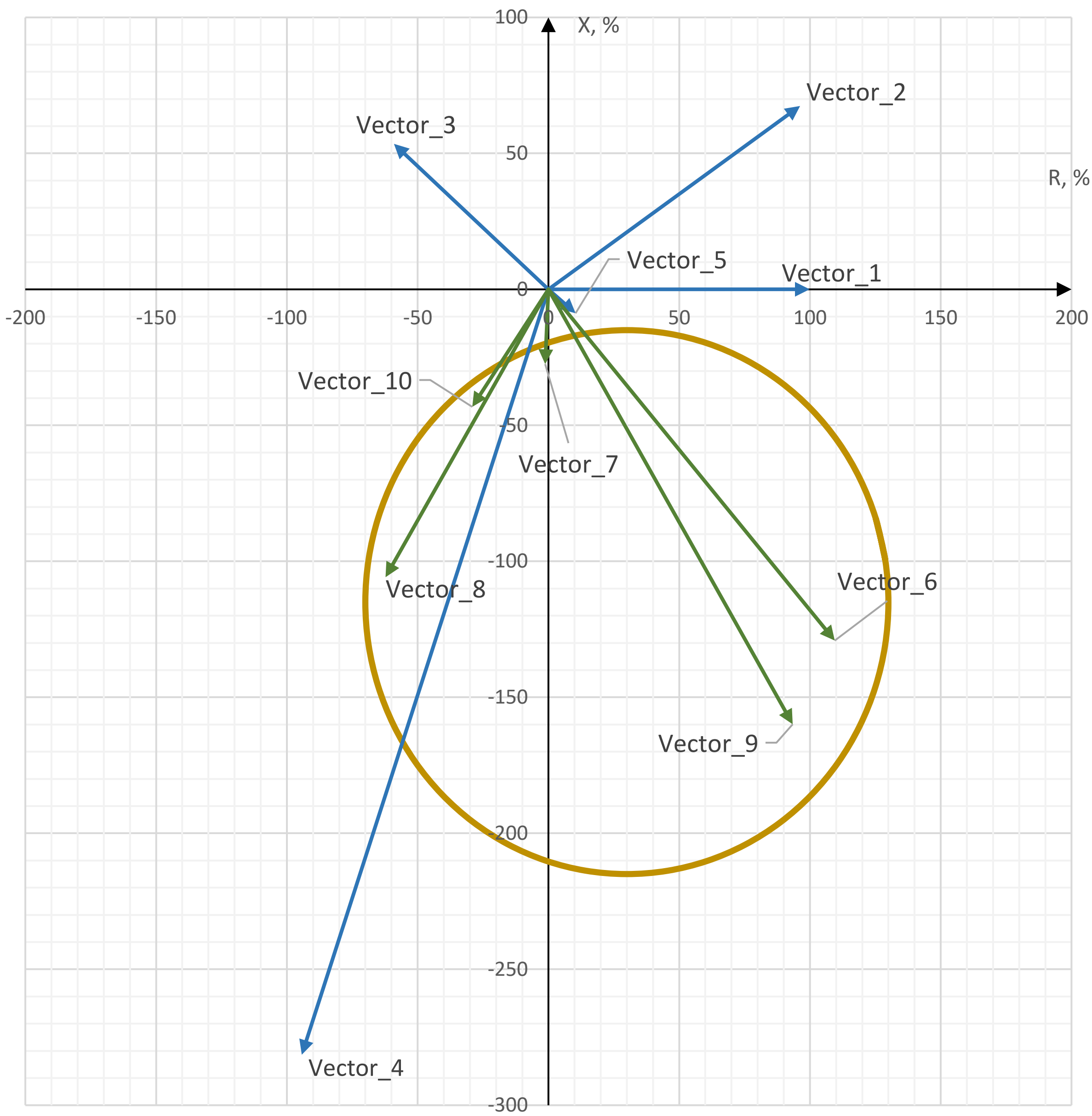


Figure 79 – The resulting graph of loss of excitation protection testing

Conclusion

The scope of this diploma thesis was to prepare the training materials for the REG 630 application for MV generator protection. The initial training will be based on the testing of three types of generator protection: differential, earth-fault, and loss of excitation protection. The steps made during the preparation of REG 630 for testing will allow building up training for engineers, who should get familiar with the REG 630 adjustment. The topics covered by this diploma thesis provide sufficient information for understanding the above-mentioned protection functionalities in the REG 630, interacting with the REG 630 configuration in PCM600, establishing the connection between the tester OMICRON CMC 310 and testing panel with the REG 630, and testing of chosen types of protection.

The key points for meeting all the objectives of the thesis were to select proper protections for testing, create the simulated module of an MV generator and its apparatus, and prepare the training materials at a satisfactory level for easy repetition of the protection testing.

The following requirements were applied for further tested protection selection: the difficulty of setting and the complexity of the testing process. According to these criteria the differential protection, earth-fault protection, and loss of excitation protection were chosen. All three types of protection are frequently applicable in real projects, have sufficiently difficult operating principles and complex requirements for testing.

The use of a real MV generator for protection testing has severe disadvantages such as cost of the equipment, lack of place, and probability of equipment damage. Hence, the MV generator and other equipment such as a circuit breaker, disconnector, and earth switch should be simulated. The chosen approach was to simulate secondary currents and voltages of a generator with the tester OMICRON CMC 310 and simulate other apparatus behavior with the Siemens LOGO and ABB PLC built-in the testing panel. For testing purposes, the generator nominal current of 100A and nominal phase-to-phase voltage of 12 kV were chosen. The corresponding secondary values for the OMICRON tester are 1A and 100V respectively. Such a choice was made to simplify further calculations and testing processes, which will increase the understanding of protection operation principles and interaction with the REG 630.

For training materials, all three protections were tested properly and the results of the testing were documented. The testing procedure includes verification of non-operation and operation zones of each protection. Therefore, currents and voltages have been chosen for protection operation or non-operation, set into OMICRON CMC 310, and then injected into the testing panel.

According to the testing procedure for the differential protection, the operation zone consisting of three sections was adjusted by PCM600. The measured values fully correspond to the settings.

The earth-fault protection testing was subdivided into non-directional earth-fault protection testing and directional earth-fault protection testing. For non-directional protection, definite and inverse definite minimum time characteristics were tested. Measurements fully correspond to set tripping times. The aim of directional earth-fault protection testing was to check if the set operating zone would coincide with the measurements. All three non-operating, forward and reverse operation zones were tested and the results fully satisfy the set parameters.

The aim of loss of excitation protection testing was to check if the set mho characteristic corresponds with the measurements. According to the measurements, the set characteristic fully coincides with the measured one.

During the elaboration of this work, knowledge about the REG 630 setting and relaying protection implementation was obtained.

The disadvantage of the solution is that faults parameters simulated during protection testing, protection settings themselves, and selected rated parameters of a generator do not correspond with the real situation. However, the aim of the initial training is not to simulate real machine and abnormal conditions, but to get familiar with the REG 630 functionalities. The diploma thesis meets the initial training requirements.

The further development of this diploma thesis is in creating the initial training, which will cover all REG 630 available functionalities, such as communication with other IED, testing of supervision and control functionalities, programming of available function buttons.

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